DOD-IR-1

Please provide a copy of all the data requests HECO has received from other parties to date.

<u>HECO Response:</u>

On April 25, 2007, the Consumer Advocate's First, Second, and Third Submissions of Information Requests were sent by courier to the DOD's representatives, Dr. Khojasteh Davoodi and Mr. Ralph Smith.

On May 16, 2007, the Consumer Advocate's Fourth Submission of Information Requests was emailed to the DOD's representatives.

DOD-IR-2

Please provide HECO's responses to all Consumer Advocate and other parties' data requests issued to date.

HECO Response:

On April 25, 2007, the requested information was sent by courier to the DOD's representatives, Dr. Khojasteh Davoodi and Mr. Ralph Smith (see pages 2 and 3 of this response).

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840

April 25, 2007

Dr. Khojasteh Davoodi
EFACHES
1322 Patterson Avenue, S.E.
Building 33, Floor 3, Room/Cube 33-3002
Washington, DC 20374

Dear Dr. Davoodi:

Subject: Docket No. 2006-0386
HECO 2007 Test Year Rate Case
Responses to DOD-IR-1 and DOD-IR-2

Enclosed are the following documents, as requested by the Department of Defense ("DOD") in its First Set of Information Requests ("IRs"):

1) The Consumer Advocate's First, Second, and Third Submissions of IRs;

2) Hawaiian Electric Company, Inc.'s ("HECO") Responses to the Consumer Advocate's First and Second Submissions of IRs, as submitted during the period beginning February 13, 2007 through March 30, 2007.

Also enclosed is a compact disc containing electronic versions of these documents. As of April 19, 2007, all of HECO's responses to the Consumer Advocate's IRs are being sent by courier to your attention.

Sincerely,

Dean K. Matsuura

Dean K. Matsuura
Director, Regulatory Affairs

Enclosure

cc: Public Utilities Commission of the State of Hawaii (w/o enclosure)
Division of Consumer Advocacy (w/o enclosure)
Ralph Smith, Larkin & Associates (w/o enclosure)
Randall Y.K. Young, Esq. (w/o enclosure)

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840

April 25, 2007

FILED
2007 APR 25 P 3: 32
PUBLIC UTILITIES COMMISSION

Mr. Ralph Smith
Larkin & Associates
15728 Farmington Road
Livonia, MI 48184

Dear Mr. Smith:

Subject: Docket No. 2006-0386
HECO 2007 Test Year Rate Case
Responses to DOD-IR-1 and DOD-IR-2

Enclosed are the following documents, as requested by the Department of Defense ("DOD") in its First Set of Information Requests ("IRs"):

1) The Consumer Advocate's First, Second, and Third Submissions of IRs;

2) Hawaiian Electric Company, Inc.'s ("HECO") Responses to the Consumer Advocate's First and Second Submissions of IRs, as submitted during the period beginning February 13, 2007 through March 30, 2007;

3) HECO's Responses to the Consumer Advocate's Third Submission of IRs, as submitted on April 19, 2007.

Also enclosed is a compact disc containing electronic versions of these documents. As of April 20, 2007, all of HECO's responses to the Consumer Advocate's IRs are being sent by courier to your attention.

Sincerely,

Dean K. Matsuura
Director, Regulatory Affairs

Enclosure

cc: Public Utilities Commission of the State of Hawaii (w/o enclosure)
Division of Consumer Advocacy (w/o enclosure)
Dr. Khojasteh Davoodi (w/o enclosure)
Randall Y.K. Young, Esq. (w/o enclosure)

DOD-IR-3

Please provide a copy of all discovery requests issued by other parties from this point forward, and also provide HECO's responses to such discovery requests at the time the responses are provided to the issuing parties.

HECO Response:

HECO will email all discovery requests to the DOD's representatives on the date the requests are received by HECO.

As of April 19, 2007, copies of HECO's responses to all discovery requests issued by other parties are being sent by courier to Dr. Khojasteh Davoodi on the date the responses are provided to the issuing party.

As of April 20, 2007, copies of HECO's responses to all discovery requests issued by other parties are being sent by courier to Mr. Ralph Smith on the date the responses are provided to the issuing party.

DOD-IR-4

To the extent not filed by HECO as part of its filing or in the response to DOD-2, please provide all Excel files and supporting workpapers for HECO witness testimony and their exhibits.

HECO Response:

All Excel files and supporting workpapers for HECO witness testimony and their exhibits were provided as part of HECO's filing or in the response to DOD-IR-2.

DOD-IR-5

Please provide the per books capital structure of Hawaiian Electric Industries, Inc. and Hawaii Electric Company at March 31, and June 30, September 30, and December 31, 2006, and March 31, 2007 (as soon as available). For the purposes of this data request, please provide the information as follows:

a) Long-term Debt (including that maturing within one year);

b) Short-term Debt;

c) Other Debt (specify);

d) Preferred or Preference Stock;

e) Common Stock;

f) Additional Paid-in Capital;

g) Retained Earnings; and

h) Total Common Equity (please identify any common equity attributable to unregulated operations, if any).

Also, please also provide published balance sheet support for each of the above-requested capital structures.

<u>HECO Response:</u>

Please see pages 2 and 3 of this response for the capital structure per books of HECO (Oahu only) and the capital structure of Hawaiian Electric Industries, Inc. as presented in SEC filings 10-Q and 10-K.

HECO (Oahu only)

Capital Structure Ratios

Periods ended	3/31/2006	6/30/2006	9/30/2006	12/31/2006	3/31/2007
Long-term debt	38.2%	37.9%	38.1%	41.7%	47.0%
Short-term debt	7.6%	8.4%	6.6%	5.1%	0.4%
Other debt	0.0%	0.0%	0.0%	0.0%	0.0%
Preferred stock	1.8%	1.8%	1.8%	1.9%	1.9%
Common stock	3.8%	3.7%	3.7%	4.1%	4.0%
Additional paid-in capital	11.2%	11.1%	11.2%	12.3%	12.0%
Accumulated other comprehensive income/(loss), less subs	0.0%	0.0%	0.0%	-8.2% *	-7.9% *
Retained earnings	37.5%	37.2%	38.6%	43.1%	42.6%
Common equity	52.4%	52.0%	53.5%	51.2% *	50.7% *
	100.0%	100.0%	100.0%	100.0%	100.0%

Balance Sheet support (HECO Oahu)
($ in thousands)

Periods ended	3/31/2006	6/30/2006	9/30/2006	12/31/2006	3/31/2007
Revenue bonds, net of discount and funds held by trustees	449,613	449,640	449,667	449,693	519,426
Long term debt payable to Trust III	31,546	31,546	31,546	31,546	31,546
Total long-term debt, net	481,159	481,186	481,213	481,239	550,972
Short-term debt from non-affiliates and subs, less loans receivable from subs	96,307	106,876	83,430	58,707	4,942
Other debt	-	-	-	-	-
Preferred stock	22,293	22,293	22,293	22,293	22,293
Common stock, less subs	47,304	47,304	47,004	47,004	47,004
Additional paid-in capital, less subs	141,250	141,250	141,250	141,250	141,250
Accumulated other comprehensive income/(loss), less subs **	(27)	(27)	(27)	(94,042) *	(92,566) *
Retained earnings, less subs ***	472,076	472,273	487,564	496,395	499,243
Common equity, HECO (Oahu)	660,603	660,800	675,791	590,607 *	594,931 *
	1,260,362	1,271,155	1,262,727	1,152,846	1,173,138

* Common stock equity includes the charges to accumulated other comprehensive income (AOCI) as a result of recording a pension and other postretirement benefits liability after implementing SFAS No. 158, on December 31, 2006.

** Includes amounts related to non-qualified pension plans and non-regulated OPEB

*** Includes both regulated and non-regulated revenues and expenses

HEI

Capital Structure Ratios

Periods ended	3/31/2006	6/30/2006	9/30/2006	12/31/2006	3/31/2007
Long-term debt	44.2%	40.2%	43.6%	46.5%	49.4%
Short-term debt	7.1%	11.5%	7.5%	7.2%	5.0%
Other debt	0.0%	0.0%	0.0%	0.0%	0.0%
Preferred stock	1.3%	1.3%	1.3%	1.4%	1.4%
Common stock	39.8%	39.8%	39.4%	42.2%	41.8%
Additional paid-in capital	0.0%	0.0%	0.0%	0.0%	0.0%
Accumulated other comprehensive income/(loss)	-2.0%	-2.5%	-1.5%	-7.2%	-6.6%
Retained earnings	9.5%	9.5%	9.7%	9.9%	9.0%
Common equity	47.3%	46.9%	47.6%	44.9%	44.2%
	100.0%	100.0%	100.0%	100.0%	100.0%

Balance Sheet information
($ in thousands)

Periods ended	3/31/2006	6/30/2006	9/30/2006	12/31/2006	3/31/2007
Long-term debt	1,133,041	1,033,089	1,133,137	1,133,185	1,225,144
Short-term debt	182,584	296,493	194,211	176,272	123,414
Other debt					
Preferred stock	34,293	34,293	34,293	34,293	34,293
Common stock	1,020,161	1,023,564	1,025,312	1,028,101	1,036,249
Additional paid-in capital					
Accumulated other comprehensive income/(loss)	(51,244)	(63,068)	(39,073)	(175,528)	(163,627)
Retained earnings	242,605	244,645	251,768	242,667	223,946
Common equity	1,211,522	1,205,141	1,238,007	1,095,240	1,096,568
	2,561,440	2,569,016	2,599,648	2,438,990	2,479,419

DOD-IR-6

For the same time periods referenced in the preceding interrogatory, please provide the following information for Hawaiian Electric Industries, Inc. and Hawaii Electric Company:

a) Embedded cost rates for long-term debt, short-term debt, other debt and preferred or preference stock;

b) Computation of embedded cost rates of long-term debt;

c) Computation of embedded cost rates of short-term debt; and

d) Computation of embedded cost rates of preferred or preference stock.

Note: Schedules should include date of issue, maturity date, dollar amount, coupon rate, net proceeds, annual interest paid and balance of principal, where applicable.

HECO Response:

a. Please see the schedule on page 3.

b. Please see schedules on pages 4-6 and 9-13 for computation of long-term debt embedded cost rates.

c. HECO and HEI do not calculate the embedded cost rate of short-term debt. HECO and HEI's short-term debt is comprised of commercial paper issuances and intercompany borrowings. Each commercial paper issuance has a stated rate which is comprised of the interest to the purchaser of the commercial paper and a fee to the commercial paper broker. Currently, HECO normally issues commercial paper with terms of 30 days or less and HEI with terms of 45 days or less. There are numerous issuances in any given quarter and the amount outstanding fluctuates throughout the quarter. The individual commercial paper transactions and intercompany borrowings are not compiled to derive a single cost rate for a quarter or any other period. HECO can also borrow funds from HEI, MECO or HELCO. If HECO borrows from MECO or HELCO, HECO pays interest on funds at a rate equal to the simple average of the effective 7-day Treasury Repurchase rate quoted by Merrill Lynch on each Friday during the month. See the response to DOD-IR-14 for information relating to the borrowing rate where HECO borrows funds from HEI.

d. Please see schedules on pages 7 and 8 for computation of preferred stock embedded cost rates for HECO. HEI does not have any outstanding preferred stock.

Embedded Cost Rates

HECO (Oahu only)

Periods ended	3/31/2006	6/30/2006	9/30/2006	12/31/2006	3/31/2007
Long-term debt (p. 6) [1]	*	*	*	5.89%	*
Short-term debt			see response to (c)		
Preferred stock (p. 8) [2]	*	*	*	5.52%	*

HEI (Parent Company only)

Periods ended	3/31/2006	6/30/2006	9/30/2006	12/31/2006	3/31/2007
Long-term debt (pp. 9-13) [3]	6.06%	5.64%	6.41%	5.61%	5.61%
Short-term debt			see response to (c)		
Preferred stock			see response to (d)		

* The Company does not calculate this information for the specified period.

[1] Based on annual interest requirements/long-term debt balance.

[2] Based on annual requirements/net proceeds.

[3] Based on quarterly interest expense/long-term debt balance multiplied by 4 (quarters).

LONG-TERM DEBT
Hawaiian Electric Company, Inc.

December 31	2006
Obligations to the State of Hawaii for repayment of special purpose revenue bonds:	
4.80%, Refunding series 2005A, due 2025 --------------	$ 40,000,000
5.00%, Refunding series 2003B, due 2022 --------------	40,000,000
5.10%, Series 2002A, due 2032 ------------------------	40,000,000
5.70%, Refunding series 2000, due 2020 ---------------	46,000,000
5.75%, Refunding series 1999B, due 2018 --------------	30,000,000
6.20%, Series 1999C, due 2029 ------------------------	35,000,000
6.15%, Refunding series 1999D, due 2020 --------------	16,000,000
4.95%, Refunding series 1998A, due 2012 --------------	42,580,000
5.65%, Series 1997A, due 2027 ------------------------	50,000,000
5 7/8%, Series 1996B, due 2026 -----------------------	14,000,000
6.20%, Series 1996A, due 2026 ------------------------	48,000,000
6.60%, Series 1995A, refunded 2005 -------------------	--
5.45%, Series 1993, due 2023 -------------------------	50,000,000
6.55%, Series 1992, refunded 2003 --------------------	--
Less funds on deposit with trustees ------------------	--
Total special purpose revenue bonds -------------	451,580,000
Notes payable to associated companies:	
8.05%, QUIDS, paid in 2004 ---------------------------	--
7.30%, QUIDS, paid in 2004 ---------------------------	--
	--
Other long-term debt - unsecured:	
7.90% note, paid in 2002 -----------------------------	--
6.50%, series 2004, Junior deferrable interest debentures, due 2034	31,546,400
Total other long-term debt - unsecured ----------	31,546,400
Total long-term debt[1] --------------------------------	483,126,400
Less unamortized discount on revenue bonds -----------	(1,886,650)
Total long-term debt, net -----------------------	$481,239,750

[1]Includes current portion of long-term debt.

LONG-TERM DEBT INTEREST REQUIREMENTS ON DEBT OUTSTANDING AT DECEMBER 31 (Annual Basis)
Hawaiian Electric Company, Inc.

December 31	2006
Interest on special purpose revenue bonds:	
4.80%, Refunding series 2005A	$ 1,920,000
5.00%, Refunding series 2003B	2,000,000
5.10%, Series 2002A	2,040,000
5.70%, Refunding series 2000	2,622,000
5.75%, Refunding series 1999B	1,725,000
6.20%, Series 1999C	2,170,000
6.15%, Refunding series 1999D	984,000
4.95%, Refunding series 1998A	2,107,710
5.65%, Series 1997A	2,825,000
5 7/8%, Series 1996B	822,500
6.20%, Series 1996A	2,976,000
6.60%, Series 1995A	--
5.45%, Series 1993	2,725,000
6.55%, Series 1992	--
	24,917,210
Interest on notes payable to associated companies:	
8.05%, QUIDS	--
7.30%, QUIDS	--
	--
Interest on other long-term debt - unsecured:	
7.90% note	--
6.50%, series 2004, Junior deferrable interest debentures	2,050,516
	2,050,516
	26,967,726

LONG-TERM DEBT INTEREST REQUIREMENTS ON DEBT OUTSTANDING AT DECEMBER 31 (Annual Basis) (continued)
Hawaiian Electric Company, Inc.

December 31	2006
Balance brought forward	$26,967,726
Amortization of debt expense and premium:	
First mortgage bonds [1]:	
Series R	--
Series S	--
Series T	--
Series U	--
Series V	--
Series X	66,633
Special purpose revenue bonds:[2]	
4.80%, Refunding series 2005A	156,754
5.00%, Refunding series 2003B	148,377
5.10%, Series 2002A	69,487
5.70%, Refunding series 2000	153,258
5.75%, Refunding series 1999B	117,854
6.20%, Series 1999C	37,330
6.15%, Refunding series 1999D	50,403
4.95%, Refunding series 1998A	216,748
5.65%, Series 1997A	54,136
5 7/8%, Series 1996B	18,946
6.20%, Series 1996A	77,315
6.60%, Series 1995A	--
5.45%, Series 1993	78,254
6.55%, Series 1992	--
QUIDS, 8.05%	40,416
QUIDS, 7.30%	37,899
Other long-term debt - unsecured:	
6.50%, series 2004, Junior deferrable interest debentures	31,099
	1,354,909
Annual debt interest requirements	$28,322,635
Long-term debt outstanding at end of year	$481,239,750
Embedded cost of long-term debt	5.89%

[1]The Series R, S, T, U, V and X first mortgage bonds were redeemed prior to maturity. The unamortized debt expense remaining at the time of redemption and the additional premium paid on early redemption is being amortized over the remaining life of the respective bonds.

[2]Includes amortization of bond discount.

PREFERRED STOCK
Hawaiian Electric Company, Inc.

December 31	2006

Cumulative preferred stock:
Authorized: 2006-2001, 5,000,000 shares of $20 par value
and 5,000,000 shares of $100 par value.

Series	Par Value	Shares Outstanding December 31, 2006	Date Issued	
Series not subject to mandatory redemption:				
C-4 1/4%	$20	150,000	October 22, 1945 --------	$3,000,000
D-5%	20	50,000	August 16, 1948 ---------	1,000,000
E-5%	20	150,000	March 20, 1950 ----------	3,000,000
H-5 1/4%	20	250,000	October 14, 1960 --------	5,000,000
I-5%	20	89,657	August 15, 1961 ---------	1,793,140
J-4 3/4%	20	250,000	June 5, 1962 ------------	5,000,000
K-4.65%	20	175,000	January 27, 1964 --------	3,500,000
		1,114,657		$22,293,140

PREFERRED STOCK DIVIDEND REQUIREMENTS (Annual Basis)
Hawaiian Electric Company, Inc.

December 31		2006
Preferred stock dividends:		
Series C, 4 1/4%	$	127,500
Series D, 5%		50,000
Series E, 5%		150,000
Series H, 5 1/4%		262,500
Series I, 5%		89,657
Series J, 4 3/4%		237,500
Series K, 4.65%		162,750
Total annual dividends		1,079,907
Amortization of preferred stock expenses		55,086
Total annual requirements	$	1,134,993

Preferred stock outstanding	$	22,293,140
Unamortized preferred stock expenses:		
Series C		70,404
Series D		55,071
Series E		183,556
Series H		59,679
Series I		64,701
Series J		49,654
Series K		39,755
Series M		156,428
Series Q		619,400
Series R		436,062
Total unamortized preferred stock expenses		1,734,710
Net proceeds	$	20,558,430
Embedded cost of preferred stock		5.52%

HEI
LONG-TERM DEBT

Description	03/31/06 Principal Balance	Principal O/S For 1Q06	Date of Note	Maturity Date	Interest Rate	1Q06 Accrued Interest
Series B - MTN	7,000,000	7,000,000	10/01/97	10/01/12	7.130%	124,775
Series B - MTN	5,000,000	5,000,000	10/01/97	10/01/07	6.930%	86,625
Series B - MTN	5,000,000	5,000,000	10/01/97	10/01/07	6.900%	86,250
Series B - MTN	0	1,194,444	02/14/96	02/14/06	6.545%	78,176
Series C - MTN	100,000,000	100,000,000	05/05/99	05/05/14	6.510%	1,627,500
Series C - MTN	100,000,000	100,000,000	04/09/01	04/10/06	7.560%	1,890,000
Series D - MTN	50,000,000	50,000,000	03/07/03	03/07/08	4.000%	500,000
Series D - MTN	50,000,000	50,000,000	03/07/03	03/07/13	5.250%	656,250
Series D - MTN	50,000,000	50,000,000	03/17/04	03/15/11	4.230%	528,750
	367,000,000	368,194,444				5,578,326

Annualized weighted average interest rate 6.06%

HEI
LONG-TERM DEBT

Description	06/30/06 Principal Balance	Principal O/S For 2Q06	Date of Note	Maturity Date	Interest Rate	2Q06 Accrued Interest
Series B - MTN	7,000,000	7,000,000	10/01/97	10/01/12	7.130%	124,775
Series B - MTN	5,000,000	5,000,000	10/01/97	10/01/07	6.930%	86,625
Series B - MTN	5,000,000	5,000,000	10/01/97	10/01/07	6.900%	86,250
Series C - MTN	100,000,000	100,000,000	05/05/99	05/05/14	6.510%	1,627,500
Series C - MTN	0	2,500,000	04/09/01	04/10/06	7.560%	189,000
Series D - MTN	50,000,000	50,000,000	03/07/03	03/07/08	4.000%	500,000
Series D - MTN	50,000,000	50,000,000	03/07/03	03/07/13	5.250%	656,250
Series D - MTN	50,000,000	50,000,000	03/17/04	03/15/11	4.230%	528,750
	267,000,000	269,500,000				3,799,150

Annualized weighted average interest rate 5.64%

HEI
LONG-TERM DEBT

Description	09/30/06 Principal Balance	Principal O/S For 3Q06	Date of Note	Maturity Date	Interest Rate	3Q06 Accrued Interest
Series B - MTN	7,000,000	7,000,000	10/01/97	10/01/12	7.130%	124,775
Series B - MTN	5,000,000	5,000,000	10/01/97	10/01/07	6.930%	86,625
Series B - MTN	5,000,000	5,000,000	10/01/97	10/01/07	6.900%	86,250
Series C - MTN	100,000,000	100,000,000	05/05/99	05/05/14	6.510%	1,627,500
Series D - MTN	50,000,000	50,000,000	03/07/03	03/07/08	4.000%	500,000
Series D - MTN	50,000,000	50,000,000	03/07/03	03/07/13	5.250%	656,250
Series D - MTN	50,000,000	50,000,000	03/17/04	03/15/11	4.230%	528,750
Series D - MTN	100,000,000	14,722,222	08/08/06	08/15/11	6.141%	904,092
	367,000,000	281,722,222				4,514,242

Annualized weighted average interest rate 6.41%

HEI
LONG-TERM DEBT

Description	12/31/06 Principal Balance	Principal O/S For 4Q06	Date of Note	Maturity Date	Interest Rate	4Q06 Accrued Interest
Series B - MTN	7,000,000	7,000,000	10/01/97	10/01/12	7.130%	124,775
Series B - MTN	5,000,000	5,000,000	10/01/97	10/01/07	6.930%	86,625
Series B - MTN	5,000,000	5,000,000	10/01/97	10/01/07	6.900%	86,250
Series C - MTN	100,000,000	100,000,000	05/05/99	05/05/14	6.510%	1,627,500
Series D - MTN	50,000,000	50,000,000	03/07/03	03/07/08	4.000%	500,000
Series D - MTN	50,000,000	50,000,000	03/07/03	03/07/13	5.250%	656,250
Series D - MTN	50,000,000	50,000,000	03/17/04	03/15/11	4.230%	528,750
Series D - MTN	100,000,000	100,000,000	08/08/06	08/15/11	6.141%	1,535,250
	367,000,000	367,000,000				5,145,400

Annualized weighted average interest rate 5.61%

HEI
LONG-TERM DEBT

Description	03/31/07 Principal Balance	Principal O/S For 1Q07	Date of Note	Maturity Date	Interest Rate	1Q07 Accrued Interest
Series B - MTN	7,000,000	7,000,000	10/01/97	10/01/12	7.130%	124,775
Series B - MTN	5,000,000	5,000,000	10/01/97	10/01/07	6.930%	86,625
Series B - MTN	5,000,000	5,000,000	10/01/97	10/01/07	6.900%	86,250
Series C - MTN	100,000,000	100,000,000	05/05/99	05/05/14	6.510%	1,627,500
Series D - MTN	50,000,000	50,000,000	03/07/03	03/07/08	4.000%	500,000
Series D - MTN	50,000,000	50,000,000	03/07/03	03/07/13	5.250%	656,250
Series D - MTN	50,000,000	50,000,000	03/17/04	03/15/11	4.230%	528,750
Series D - MTN	100,000,000	100,000,000	08/08/06	08/15/11	6.141%	1,535,250
	367,000,000	367,000,000				5,145,400

Annualized weighted average interest rate 5.61%

DOD-IR-8

With regard to the most recent available published balance sheets for Hawaiian Electric Company, please respond to the following:

a) Please identify any debt or other liability that is directly attributable to, or is deemed to support unregulated operations. If not, please so specify.

b) Please identify any assets on the balance sheet that are not listed specifically as utility plant investment (e.g., cash investment balances, land held for future non-regulatory use, investments in unregulated companies (identify each)).

<u>HECO Response:</u>

a. There are no debt issues or other liability that is directly attributable or deemed to support unregulated (i.e., non-utility) operations.

b. Please refer to HECO's response to CA-IR-147, part d.

DOD-IR-7

a) Please list all of Hawaiian Electric Industries' subsidiaries, providing a short description of the business of each and indicate whether or not the subsidiary is active or inactive.

b) Please list all of Hawaiian Electric Company's subsidiaries, providing a short description of the business of each and indicate whether or not the subsidiary is active or inactive.

c) Please provide a consolidating (not consolidat<u>ed</u>) balance sheet for Hawaiian Electric Industries at December 31, 2006, or the most recent date available.

d) Please provide a consolidat<u>ing</u> (not consolidat<u>ed</u>) balance sheet for Hawaiian Electric Company at December 31, 2005, or the most recent date available.

<u>HECO Response:</u>

For a list of Hawaiian Electric Industries, Inc.'s ("HEI") subsidiaries and a short description of each business, please refer to the SEC filing Form 10-K for the fiscal year ended December 31, 2006, pages 1 and 2, which was submitted on April 23, 2007, as pages 197 and 198 in the revised response to CA-IR-5 (revised April 20, 2007). HEI Capital Trust II and III are inactive financing entities, as noted on page ii of the SEC filing Form 10-K for the fiscal year ended December 31, 2006, found on page 193 in the revised response to CA-IR-5 (revised April 20, 2007).

a. For a list of Hawaiian Electric Company's subsidiaries and a short description of each business, please refer to the SEC filing Form 10-K for the fiscal year ended December 31, 2006, page 2, found on page 198 in the revised response to CA-IR-5 (revised April 20, 2007).

b. HECO objects to providing the consolidating balance sheet for Hawaiian Electric Industries ("HEI") on the grounds that the information (1) is considered non-public information, (2) may be misinterpreted if released selectively and/or not read in conjunction with HEI's periodic and other filings with the Securities and Exchange Commission, and (3) is irrelevant to the issues in this proceeding. While HEI is the parent of HECO, the

Commission generally ruled that HEI, as a diversified holding company, is not an appropriate proxy for HECO or its utility subsidiaries in determining their cost of capital. (See Decision and Order No. 11317 in Docket No. 6531 (HECO's 1990 Test Year) and Decision and Order No. 10993 in Docket No. 6432 (HELCO's 1990 Test Year).) Without waiving its objection, the Company submits HEI's consolidating balance sheet as of March 31, 2007 on page 3 pursuant to Protective Order No. 23378.

c. The consolidating balance sheet for Hawaiian Electric Company as of March 31, 2007, can be found in the SEC filing Form 10-Q, page 31, which was provided in HECO's response to DOD-IR-9.

Page 3 contains confidential information and is being provided pursuant to Protective Order No. 23378, issued on April 23, 2007.

DOD-IR-9

Please provide the 2006 S.E.C. Form 10-K as soon as it is available and any 10-Qs and 8-Ks issued by Hawaiian Electric Industries, Inc. since January 1, 2006.

<u>HECO Response:</u>

See HECO's response to CA-IR-5 (revised April 20, 2007), for the HEI/HECO 2006 SEC Form 10-K. HEI/HECO's Form 10-Q's for 2006 and the first quarter of 2007 and the Form 8-Ks issued since January 1, 2006 is voluminous. The information is available for inspection at HECO's Regulatory Affairs Division office, Suite 1301, Central Pacific Plaza, 220 South King Street, Honolulu, Hawaii. Please contact Dean Matsuura at 543-4622 to make arrangements to inspect the requested information. Electronic versions of the requested information are being provided on a compact disc.

The requested information is also publicly available at HEI's website, http://www.hei.com, under "SEC Filings" and at the SEC website listed below:

http://www.sec.gov/cgi-bin/browse-edgar?company=&CIK=he&filenum=&State=&SIC=&owner=include&action=getcompany.

DOD-IR-10

Please provide, as soon as available, Hawaiian Electric Industries' 2006 Annual Report to Shareholders (as well as any statistical supplements available to investors). Also, if Hawaiian Electric Company provides a separate Annual Report, please provide that document as well.

HECO Response:

See response to CA-IR-5 (revised April 20, 2007) regarding Hawaiian Electric Industries, Inc.'s 2006 Annual Report to Shareholders and the statistical supplement. Hawaiian Electric Company, Inc.'s annual report was filed as an exhibit (Exhibit 99.4) to the 2006 HECO/HEI SEC Form 10-K, which was included in the revised response to CA-IR-5.

DOD-IR-11

Please provide a copy of the most recent bond rating agency (Standard & Poor's, Moody's, Fitch) report for Hawaiian Electric Industries, Inc. and separately, if available, for Hawaiian Electric Company. [Note: Report provided should be most recent in-depth report, not a one or two-page update.]

HECO Response:

Please see attached for a copy of the most recent reports for HECO and HEI by Standard & Poor's dated May 23, 2007 and March 26, 2007, respectively; and by Moody's Investor Services dated December 21, 2006. HEI and HECO no longer employ the services of Fitch.

Note: Most (if not all) of the information requested is copyrighted. The copies are being provided under the "fair use" exception to the copyright laws. Any copies made of the requested information are subject to copyright laws.

STANDARD & POOR'S RatingsDirect

RESEARCH

Research Update:

Hawaiian Electric Ratings Cut To 'BBB'; Outlook Stable

Publication date: 23-May-2007
Primary Credit Analysts: Barbara A Eiseman, New York (1) 212-438-7666; barbara_eiseman@standardandpoors.com
Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

Rationale

On May 23, 2007, Standard & Poor's Ratings Services lowered its long-term corporate credit and unsecured debt ratings on Hawaiian Electric Co. Inc., Hawaiian Electric Light Co. Inc. (HELCO), and Maui Electric Co. Ltd. (MECO) to 'BBB' from 'BBB+'. Standard & Poor's affirmed its 'A-2' short-term corporate credit rating on Hawaiian Electric. The outlook is stable.

Hawaiian Electric is a subsidiary of diversified holding company Hawaiian Electric Industries Inc. (HEI) whose ratings were affirmed. Standard & Poor's also revised its outlook on HEI to stable from negative.

The downgrade of Hawaiian Electric is the result of sustained weak bondholder protection parameters compounded by the financial pressure that continuous need for regulatory relief, driven by heightened capital expenditure requirements, is creating for the next few years.

The ratings on HEI are based on the consolidated credit profile of HEI's units, which include Hawaiian Electric and its units (83% of core revenues and 65% of operating income as of Dec. 31, 2006) and the financial services operations of American Savings Bank FSB (17% of core revenues and 35% of operating income). Standard & Poor's does not accord any credit uplift to American Savings Bank as a result of its affiliation with HEI.

HEI's financial condition remains weak for the rating despite the healthy Hawaiian economy and the company's efforts in recent years to strengthen its capital structure. Financial metrics have been pressured owing to rising operating and maintenance expenses, increasing capital outlays, and recently, lower electricity sales caused by cooler less humid weather and customer conservation. Absent responsive rate orders in Hawaiian Electric's pending rate cases, prospective key financial metrics may not support a financial profile that is commensurate with the current ratings.

HEI and Hawaiian Electric have satisfactory business profiles of '5' (business profiles are ranked from '1' (excellent) to '10' (vulnerable) and somewhat weak financial measures. HEI's business position is characterized by limited competitive threats due to the utility's geographic isolation, nominal stranded-asset risk, a good fuel adjustment clause, and solid banking operations. These strengths are tempered by Hawaii's economic dependence on a limited number of industries, reliance on fuel oil, strained capacity reserve margins, and significant purchased power obligations. With regard to the bank, its earnings have been challenged by margin compression and rising interest costs.

A responsive final rate order from the Hawaii Public Utilities Commission (PUC) with regard to Hawaiian Electric's 2005 rate case is crucial to help lift key financial measures to more appropriate levels for the ratings. In September 2005, the PUC issued an interim net rate hike of $41.1 million (3.3%) that is marginally supportive of current ratings. If the amount collected under the interim increase exceeds the amount of the increase ultimately approved in the PUC's final decision and order, the company must refund the excess to its ratepayers with interest. There are no time restrictions in which the PUC must issue a final order.

In December 2006, Hawaiian Electric filed for a $99.6 million (7.1%) rate increase. Also pending before the PUC is MECO's request for a $19 million

(5.3%) rate increase and HELCO's application for a $29.9 million (9.24%) rate hike. The PUC must issue an interim decision within 11 months, indicating possible interim orders in mid 2007 to early 2008. Rate relief is targeted toward enhancing earnings and recovering increased costs and reliability investments.

Of some concern is Hawaii's Act 162, a new law which appears to confirm, in light of the state legislature's interest in promoting renewable energy, the PUC's ability to authorize the utility's fuel adjustment clause. Although no parties to the rate case seem to oppose the continuation of the clause, a material change to the fuel adjustment mechanism would harm the company's financial condition and detract from its currently satisfactory business profile.

A final order that closely mirrors the interim ruling on Hawaiian Electric's 2005 rate case, as well as a supportive order in its most recently filed rate application, will be critical to lift key financial metrics to levels that are suitable for Standard & Poor's guideposts for the 'BBB' rating category. Responsive rate decisions on HELCO's and MECO's pending rate cases will also help to support credit quality. With regard to HELCO, a settlement was reached for about 85% of the amount sought, or a $24.6 million (7.6%) rate hike. Importantly, the Consumer Advocate determined that the fuel adjustment clause complied with Act 162 and should be continued.

Hawaii's economic growth is expected to be tied primarily to the rate of expansion in the mainland U.S. and Japan economies and increased military spending. The state's economy grew by an estimated 2.7% in 2006 and is expected to grow by 2.6% in 2007. Military and federal government spending remains strong as the U.S. Department of Defense has redeployed military assets to Hawaii. Tourism is also a significant component of the Hawaii economy, with visitor expenditures up 2.9% and visitor days slightly down 0.3%, respectively, in 2006 compared with record levels in 2005. Continued growth is expected in 2007, with projected increases of 1.5% in visitor days and 4.8% in visitor expenditures. Although the housing market appears to be stabilizing, the construction industry continues to be healthy as indicated by an 8% increase in 2006 building permits compared to 2005. However, future growth in residential construction may slow with rising interest rates.

The company's projected $1.2 billion capital expenditure program over the next five years will focus predominantly on additions and improvements to transmission and distribution facilities (approximately 51%) and on generation projects (approximately 41%). The balance is for general plant and other projects. These estimates don't include outlays, which could be substantial, that would be required to comply with cooling water intake structure regulations or Regional Haze Rule amendments. Standard & Poor's expects that consolidated cash flow from operations will fall short of covering projected capital expenditures and dividends in nearby years, resulting in increased reliance on outside capital.

HEI has certain bondholder protection metrics that are subpar for the current ratings. In this regard, total debt to capital (adjusted for purchased-power contracts, pensions and applying intermediate equity treatment to HECO's hybrids preferred securities) and funds from operations (FFO) to total debt are somewhat weak at roughly 61% and 16%, respectively. Adjusted FFO interest coverage remains healthy at about 3.5x. Accordingly, rate relief, tight cost controls, improved earnings, and credit supportive actions by management will be required to lift the company's overall financial profile to more suitable levels.

Short-term credit factors

The short-term corporate credit and commercial paper ratings on HEI and Hawaiian Electric are 'A-2'. Ongoing growth in the Hawaii economy should allow the electric utility to generate relatively stable cash flows. However, accelerating capital expenditures will necessitate a somewhat higher reliance rate relief and on external capital in nearby years.

HEI maintains a $100 million unsecured revolving syndicated credit facility that expires on March 31, 2011. The covenants require HEI to maintain a nonconsolidated capitalization ratio of 50% or less and consolidated net worth of $850 million, with which the company is in compliance.

Hawaiian Electric maintains a $175 million unsecured revolving syndicated credit facility that expires on March 31, 2011. Pursuant to the agreement, the company must maintain a consolidated common stock equity to capitalization ratio of at least 35%, with which the company is in compliance.

Both HEI's and Hawaiian Electric's facilities support the issuance of commercial paper, but may also be drawn for general corporate purposes. Hawaiian Electric's facility may also be drawn for capital expenditures. The facilities do not contain interest coverage ratio requirements, material adverse change clauses, or rating triggers. As of May 1, 2007, both HEI's and Hawaiian Electric's credit facilities were undrawn.

HEI has just $10 million coming due in October 2007 and Hawaiian Electric has no maturing long-term debt until 2012. As of March 31, 2007, HEI had $14.1 million of cash and cash equivalents (excluding American Savings Bank's cash and cash equivalents).

HEI has $50 million of debt capacity remaining under a Rule 415 shelf registration and $96 million remains on an omnibus shelf registration.

Outlook

The stable outlook on Hawaii Electric reflects expectations for supportive regulatory decisions in several pending rate cases and continued health in the Hawaii economy. Unsupportive rate treatment that would result in the erosion of key financial parameters, especially cash flow coverage of debt, and a slump in the Hawaiian economy could lead to downward rating pressure. Higher ratings are not foreseen over the outlook horizon, given HEI's relatively liberal debt burden and weak FFO to total debt ratio.

Ratings List

Downgraded

	To	From
Hawaiian Electric Co. Inc.		
Corporate Credit Rating	BBB/Stable/A-2	BBB+/Negative/A-2
Senior Unsecured	BBB	BBB+
Preferred Stock	BB+	BBB-
Hawaii Electric Light Co. Inc.		
Maui Electric Co. Ltd.		
Corporate Credit Rating	BBB/Stable/--	BBB+/Negative/--
Senior Unsecured	BBB	BBB+

Ratings Affirmed

Hawaiian Electric Co. Inc.		
Commercial Paper	A-2	
Hawaiian Electric Industries Inc.		
Corporate Credit Rating	BBB/Stable/A-2	BBB/Negative/A-2
Senior Unsecured	BBB	
Preferred Stock	BB+	

Complete ratings information is available to subscribers of RatingsDirect, the real-time Web-based source for Standard & Poor's credit ratings, research, and risk analysis, at www.ratingsdirect.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com; under Credit Ratings in the left navigation bar, select Find a Rating, then Credit Ratings Search.

STANDARD &POOR'S RatingsDirect

RESEARCH

Summary:

Hawaiian Electric Industries Inc.

Publication date: 26-Mar-2007
Primary Credit Analyst: Barbara A Eiseman, New York (1) 212-438-7666; barbara_eiseman@standardandpoors.com

Credit Rating: BBB/Negative/A-2

Rationale

The ratings on diversified holding company Hawaiian Electric Industries Inc. (HEI) are based on the consolidated credit profile of HEI's units, which include the electric utility, Hawaiian Electric Co. Inc. and its two subsidiaries Hawaiian Electric Light Co. (HELCO) and Maui Electric Co. (83% of core revenues and 65% of operating income as of Dec. 31, 2006) and the riskier financial services operations of American Savings Bank FSB (17% of core revenues and 35% of operating income). Standard & Poor's Ratings Services does not accord any credit uplift to American Savings Bank as a result of its affiliation with HEI.

HEI's financial condition remains weak for the rating despite the healthy Hawaiian economy and the company's efforts in recent years to strengthen its capital structure. Financial metrics have been pressured owing to rising operating and maintenance expenses, increasing capital outlays, and recently, lower electricity sales caused by cooler less humid weather and customer conservation. Absent responsive rate orders in Hawaiian Electric's pending rate cases, prospective key financial metrics may not support a financial profile that is commensurate with the current ratings.

HEI and Hawaiian Electric have satisfactory business profiles of '6' and '5', respectively, (business profiles are ranked from '1' (excellent) to '10' (vulnerable)) and somewhat weak financial measures. HEI's business position is characterized by limited competitive threats due to the utility's geographic isolation, nominal stranded-asset risk, a currently excellent fuel clause, and relatively steady banking operations. These strengths are tempered by Hawaii's economic dependence on a limited number of industries, reliance on fuel oil, strained capacity reserve margins, significant purchased power obligations, and support of the somewhat riskier banking business. Hawaiian Electric's business profile is slightly stronger than that of the parent due to the absence of nonutility operations. With regard to the bank, its earnings have been challenged by margin compression and rising interest costs.

A responsive final rate order from the Hawaii Public Utilities Commission (PUC) with regard to Hawaiian Electric's 2005 pending rate case is crucial to help lift key financial measures to more appropriate levels for the ratings. In September 2005, the PUC issued an interim net rate hike of $41.1 million (3.3%) that is marginally supportive of current ratings. If the amount collected under the interim increase exceeds the amount of the increase ultimately approved in the PUC's final decision and order, the company must refund the excess to its ratepayers with interest. A final order that closely mirrors the interim ruling appears to be sufficient to lift key financial metrics to levels that are marginally suitable for Standard & Poor's guideposts for the 'BBB' rating category. There are no time restrictions in which the PUC must issue a final order.

In December 2006, Hawaiian Electric also filed for a $99.6 million (7.1%) rate increase. Also pending before the PUC is Maui Electric's request for a $19 million (5.3%) rate increase and HELCO's application for a $29.9 million (9.24%) rate hike. The PUC must issue an interim decision within 11 months, indicating possible interim orders in mid-2007 to early 2008. Rate relief is needed to enhance the earnings and recover increased costs and reliability investments.

Of some concern is Hawaii's Act 162, a new law which appears to confirm, in light of the state legislature's interest in promoting renewable energy, the PUC's ability to authorize the utility's fuel adjustment clause. Although no parties to the rate case seem to oppose the continuation of the clause, a material change to fuel-adjustment mechanism would harm the company's financial condition and detract from its currently satisfactory business profile.

Hawaii's economy grew by an estimated 2.7% in 2006 and is expected to grow by 2.6% in 2007. Military and federal government spending remains strong as the U.S. Department of Defense has moved military assets to Hawaii. Tourism is also a significant component of the Hawaii economy, with visitor expenditures up 2.9% and visitor days slightly down 0.3%, respectively in 2006 compared with record levels in 2005. Continued growth is expected in 2007, with projected increases of 1.5% in visitor days and 4.8% in visitor expenditures. Although the housing market appears to be stabilizing, the construction industry continues to be healthy as indicated by an 8% increase in 2006 building permits compared to 2005. However, future growth in residential construction may slow with rising interest rates. Hawaii's economic growth is expected to be tied primarily to the rate of expansion in the mainland U.S. and Japan economies and increased military spending, yet remains vulnerable to uncertainties in the world's geopolitical environment.

The company's projected $1.2 billion capital expenditure program over the next five years will focus predominantly on additions and improvements to transmission and distribution facilities (approximately 51%) and on generation projects (approximately 41%). The balance is for general plant and other projects. These estimates do not include outlays, which could be substantial, that would be required to comply with cooling water intake structure regulations or Regional Haze Rule amendments. Standard & Poor's expects that consolidated cash flow from operations will fall short of covering projected capital expenditures and dividends in nearby years, resulting in increased reliance on outside capital.

HEI has certain bondholder protection metrics that are subpar for the current ratings. In this regard, total debt to capital (adjusted for purchased-power contracts, pensions, and applying intermediate equity treatment to HECO's hybrids preferred securities) and funds from operations (FFO) to total debt are somewhat weak at roughly 61% and 16%, respectively. Adjusted FFO interest coverage remains healthy at about roughly 3.6x. Accordingly, rate relief, tight cost controls, improved earnings, and credit supportive actions by management will be required to lift the company's overall financial profile to more suitable levels.

Short-term credit factors

The short-term corporate credit and commercial paper ratings on HEI and Hawaiian Electric are 'A-2' incorporating solid liquidity, a manageable maturity ladder, and ongoing growth in the Hawaii economy that should allow the electric utility to generate relatively stable cash flows. However, accelerating capital expenditures will necessitate a somewhat higher reliance on external capital in nearby years.

HEI maintains a $100 million unsecured revolving syndicated credit facility which expires on March 31, 2011. The covenants require HEI to maintain a nonconsolidated capitalization ratio of 50% or less and consolidated net worth of $850 million, with which the company is in compliance.

Effective April 3, 2006, Hawaiian Electric entered into a $175 million unsecured revolving syndicated credit facility that expires on March 29, 2007, but will automatically extend to March 31, 2011 if the longer-term agreement is approved by the PUC. Pursuant to the agreement, the company must maintain a consolidated common stock equity to capitalization ratio of at least 35%, with which the company is in compliance.

Both HEI's and Hawaiian Electric's facilities support the issuance of commercial paper, but may also be drawn for general corporate purposes. Hawaiian Electric's facility may also be drawn for capital expenditures. The facilities do not contain interest coverage ratio requirements, material adverse change clauses, nor rating triggers. As of the end of 2006, both HEI's and Hawaiian Electric's credit facilities were undrawn.

HEI has just $10 million due in October 2007 and Hawaiian Electric has no maturing long-term debt until 2012. As of Dec. 31, 2006, HEI had $5.3 million of cash and cash equivalents (excluding American Savings Bank's cash and cash equivalents).

HEI has $50 million of debt capacity remaining under a Rule 415 shelf registration and $96 million remains on an omnibus shelf registration.

Outlook

The negative outlook on HEI reflects the company's subpar financial condition relative to the rating level. Failure to strengthen key financial parameters, especially cash flow coverage of debt, a slump in the Hawaiian economy, a final rate order that differs from the PUC's interim decision with regard to HECO's 2005 rate case, and, although not expected, a major erosion in American Savings Bank's creditworthiness could lead to lower ratings. Conversely, credit-supportive actions by the company as well as responsive rate treatment would lead to ratings stability.

Moody's Investors Service

Global Credit Research
Credit Opinion
21 DEC 2006

Credit Opinion: Hawaiian Electric Company, Inc.

Hawaiian Electric Company, Inc.

Honolulu, Hawaii, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	Baa1
Preferred Stock	Baa3
Bkd Commercial Paper	P-2
Parent: Hawaiian Electric Industries, Inc.	
Outlook	Stable
Senior Unsecured	Baa2
Bkd Commercial Paper	P-2
HECO Capital Trust III	
Outlook	Stable
Bkd Preferred Stock	Baa2

Contacts

Analyst	Phone
A.J. Sabatelle/New York	1.212.553.1653
Laura Schumacher/New York	
William L. Hess/New York	

Key Indicators

Hawaiian Electric Company, Inc.

	Q306LTM	2005	2004	2003	2002
(CFO Pre-W/C + Interest) / Interest	4.4	4.7	4.6	4.5	4.4
(CFO Pre-W/C) / Debt	19.5%	19.5%	20.2%	22.0%	21.2%
(CFO Pre-W/C - Dvidends) / Debt	15.0%	14.5%	18.9%	14.5%	15.5%
(CFO Pre-W/C - Dvidends) / Capex	73.2%	68.7%	87.2%	88.1%	124.7%
Debt / Book Capitalization	49.2%	49.6%	47.1%	47.6%	49.6%
EBITDA Margin	8.2%	8.8%	10.8%	12.9%	15.4%

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Company Profile

Hawaiian Electric Company, Inc. (HECO) and its operating subsidiaries, Maui Electric Company, Limited (MECO) and Hawaii Electric Light Company, Inc. (HELCO) are regulated electric public utilities that provide electricity to 95% of the state's 1.2 million residents on the islands of Oahu, Maui, Hawaii, Lanai and Molokai. HECO serves the island of Oahu; MECO serves the islands of Maui, Molokai, and Lanai; and HELCO serves the island of Hawaii. HECO is a wholly-owned subsidiary of Hawaiian Electric Industries, Inc.

Rating Rationale

HECO's Baa1 Issuer Rating reflects the relative earnings and cash flow stability of this vertically integrated utility, the relatively strong service territory growth that continues at HECO and its subsidiaries, the company's conservative financial management, including its back-to-basics business strategy, and the historically strong financial metrics that have resulted for this medium size utility. The rating also considers the increasing size of the company's capital programs, the need for timely regulatory support to help finance capital investment and to maintain credit quality, and the associated challenges to implement rate increases in a state where retail electric rates are high.

Key Credit Factors

1. Historically, HECO has produced relatively stable credit metrics.

HECO has historically been a stable producer of earnings and cash flow due to its position as a vertically integrated utility that serves 95% of the state, a growing service territory, and the receipt of incremental rate relief, including the September 2005 interim rate decision from the Hawaii Public Utilities Commission (Hawaii PUC). For the past three years, HECO's ratio of cash flow to adjusted debt has averaged around 20% and the ratio of cash flow to adjusted interest has averaged around 4.5 times over the same period. These financial measures, which incorporate Moody's standard adjustments, are consistent with a high Baa rated vertically-integrated utility and are in accordance with the guidelines in Moody's rating methodology for electric utilities in the mid-range of the medium global risk category.

2. Relatively strong service territory growth that continues to diversify

During 2005, the state's economy grew by 4.0% and it is expected to grow at around 3.3% for 2006. Economic growth continues to be fueled by strength in the tourism sector and from growth by the federal government. 2005 was a record year for tourism in Hawaii, with visitor days exceeding the 2004 record by 7.7%. For the first eight months of 2006, visitor days were relatively flat compared to the same period for 2005, but expenditures were up 4.5%. In recent years, the growth of federal government spending, principally military spending, has caused the Hawaiian economy to become less dependent upon tourism as a principal source of economic expansion. For example, total federal government expenditures in Hawaii, including military expenditures, were $12.2 billion in fiscal year 2004, an increase of 8% over fiscal year 2003. Military spending, which is 39% of federal expenditures in Hawaii, increased 6% in fiscal year 2004 compared to fiscal year 2003.

3. Regulatory Support Remains Critical to Maintenance of Credit Quality

As noted in Moody's Rating Methodology for Global Regulated Electric Utilities, the supportiveness of the regulatory framework under which a utility operates is a critical rating factor. While regulatory decisions rendered by the Hawaii PUC have generally resulted in supportive outcomes, Moody's notes an increasing degree of regulatory lag that exists in reaching final decisions in Hawaii. For example, HECO is still operating under an interim order reached in September 2005 and along with subsidiaries, MECO and HELCO, have either filed or intend to file additional rate requests in the near future due to the need to recover higher operating expenses. Additionally, supply and reliability related issues have surfaced throughout the state due to the growth in the economy and the age and inefficiency of some of the existing resources in the state. Given the increasing need for additional generation and reliability related resources, timely and supportive regulatory decisions remain key to the maintenance of HECO's credit quality.

4. Capital Programs for Utility Infrastructure Has Increased.

Capital expenditures for 2004 and 2005 exceeded $200 million annually and capital expenditures for 2006 are expected to be in a similar range. Most of the capital investment has been associated with transmission and distribution investments as well as new generation resources, all intended to meet growing demand and to improve reliability and supply options that exist on an aging electric system. HECO has also invested heavily in demand side management programs that are intended to reduce consumption and head off the need for additional peak time resources. Reflective of this capital investment requirement has been HECO's increase in operation and maintenance expense associated with their need to operate older, less efficient generation more frequently in order to satisfy higher demand requirements. HECO and its subsidiaries' ability to obtain timely and supportive regulatory treatment for its capital investment program remains an important rating consideration.

Rating Outlook

HECO's stable rating outlook reflects an expectation that the company will continue to manage its growth in a conservative fashion, that timely regulatory support for the company's sizeable capital program will occur, and that management will remain focused around its current back-to-basics business strategy.

What Could Change the Rating - Up

In light of the sizeable capital investment programs and the uncertainty that surrounds associated rate case decisions and rate requests contemplated by HECO and its subsidiaries, limited near-term prospects exist for the rating to be upgraded.

What Could Change the Rating - Down

The rating could be downgraded should weaker than expected regulatory support emerge, including the continuation of regulatory lag, which ultimately causes earnings and sustainable cash flow to suffer.

Rating Factors

Hawaiian Electric Company, Inc.

Select Key Ratios for Global Regulated Electric Utilities

Rating	Aa	Aa	A	A	Baa	Baa	Ba	Ba
Level of Business Risk	Medium	Low	Medium	Low	Medium	Low	Medium	Low
CFO pre-W/C to Interest (x) [1]	>6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
CFO pre-W/C to Debt (%) [1]	>30	>22	22-30	12-22	13-25	5-13	<13	<5
CFO pre-W/C - Dividends to Debt (%) [1]	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Total Debt to Book Capitalization (%)	<40	<50	40-60	50-70	50-70	60-75	>60	>70

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

Moody's Investors Service

Global Credit Research
Credit Opinion
21 DEC 2006

Credit Opinion: Hawaiian Electric Industries, Inc.

Hawaiian Electric Industries, Inc.

Honolulu, Hawaii, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Senior Unsecured	Baa2
Bkd Commercial Paper	P-2
American Savings Bank, FSB	
Outlook	Stable
Bank Deposits	Baa2/P-2
Issuer Rating	Baa3
Hawaiian Electric Industries Capital Trust I	
Outlook	Stable
Bkd Preferred Stock	Ba1
HEI Preferred Funding, L.P.	
Outlook	Stable
Bkd Jr Subordinate Shelf	(P)Ba1
Hawaiian Electric Industries Capital Tr. III	
Outlook	Stable
Bkd Preferred Shelf	(P)Ba1

Contacts

Analyst	Phone
A.J. Sabatelle/New York	1.212.553.1653
Laura Schumacher/New York	
William L. Hess/New York	

Key Indicators

Hawaiian Electric Industries, Inc.

	Q306LTM	2005	2004	2003	2002
(CFO Pre-W/C + Interest) / Interest	3.9	3.8	3.6	3.7	4.1
(CFO Pre-W/C) / Debt	17.2%	16.9%	16.0%	18.1%	20.4%
(CFO Pre-W/C - Dvidends) / Debt	10.4%	9.9%	9.1%	12.6%	15.3%
(CFO Pre-W/C - Dvidends) / Capex	68.8%	63.5%	57.2%	105.6%	173.0%
Debt / Book Capitalization	53.1%	52.6%	51.9%	54.1%	56.3%
EBITDA Margin	10.9%	12.1%	14.1%	16.3%	15.7%

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Company Profile

Hawaiian Electric Industries, Inc. (HEI) is a holding company with its principal subsidiaries engaged in the electric utility, banking and other businesses operating primarily in the State of Hawaii. Hawaiian Electric Company, Inc. (HECO) and its subsidiaries, Hawaii Electric Light Company, Inc. (HELCO) and Maui Electric Company, Limited (MECO) supplies power to 95% of the Hawaii electric public utility market. HECO serves the island of Oahu; MECO serves the islands of Maui, Molokai, and Lanai; and HELCO serves the island of Hawaii. Moody's currently has assigned a Baa1 Issuer Rating to HECO.

In addition to HECO and its subsidiaries, HEI's largest direct subsidiary holding is American Savings Bank, F.S.B., (ASB) the state's third largest financial institution based on asset size. At December 31, 2005, ASB had total assets of $6.8 billion and deposits of $4.6 billion. In 2005, ASB's revenues and net income from continuing operations amounted to approximately 18% and 47%, respectively, of HEI's consolidated amounts, excluding any contributions from the holding company only level. Moody's has assigned a Baa2 Long-Term Bank Deposit Rating to ASB.

Rating Rationale

HEI's Baa2 senior unsecured rating reflects the relatively stable earnings and cash flow provided by its vertically integrated utility business and from the market position held by ASB, the third largest financial institution in Hawaii. The rating further reflects the relatively strong economic growth that continues within the state, which indirectly benefits both subsidiary businesses, the company's conservative financial management, including its back-to-basics business strategy, and the historically strong financial metrics that have resulted for this medium size utility. The rating also recognizes the concentration risk that exists for this enterprise, the increasing size of the company's capital programs, the need for timely regulatory support to help finance capital investment and to maintain credit quality at HECO and at HEI, and the associated challenges to implement rate increases at HECO in a state where retail electric rates are high.

Key Credit Factors

1. Historically, HEI has produced relatively stable credit metrics.

HEI has historically been a stable producer of earnings and cash flow due to its position as a vertically integrated utility that serves 95% of the state and its position as the third largest financial institution in the state. For the past three years, HEI's ratio of cash flow to adjusted debt has averaged around 17% and the ratio of cash flow to adjusted interest has averaged around 3.9 times over the same period. These financial measures, which incorporate Moody's standard adjustments, are consistent with a Baa rated vertically-integrated utility and are in accordance with the guidelines in Moody's rating methodology for electric utilities in the mid-range of the medium global risk category. While 51% of HEI's net income is generated from a non-utility business, we view the earnings potential of ASB to be relatively stable, particularly given the historical earnings at the bank as well as its competitive position in the state, which provides it with an important funding source.

2. Relatively strong economy that continues to diversify

During 2005, the state's economy grew by 4.0% and it is expected to grow at around 3.3% for 2006. Economic growth continues to be fueled by strength in the tourism sector and from growth by the federal government. 2005 was a record year for tourism in Hawaii, with visitor days exceeding the 2004 record by 7.7%. For the first eight months of 2006, visitor days were relatively flat compared to the same period for 2005, but expenditures were up 4.5%. In recent years, the growth of federal government spending, principally military spending, has caused the Hawaiian economy to become less dependent upon tourism as a principal source of economic expansion. For example, total federal government expenditures in Hawaii, including military expenditures, were $12.2 billion in fiscal year 2004, an increase of 8% over fiscal year 2003. Military spending, which is 39% of federal expenditures in Hawaii, increased 6% in fiscal year 2004 compared to fiscal year 2003.

3. Regulatory Support Remains Critical to Maintenance of Credit Quality at HECO

As noted in Moody's Rating Methodology for Global Regulated Electric Utilities, the supportiveness of the regulatory framework under which a utility operates is a critical rating factor. While regulatory decisions rendered by the Hawaii PUC have generally resulted in supportive outcomes, Moody's notes an increasing degree of regulatory lag that exists in reaching final decisions in Hawaii. For example, HECO is still operating under an interim order reached in September 2005 and along with subsidiaries, MECO and HELCO, have either filed or intend to file additional rate requests in the near future due to the need to recover higher operating expenses. Additionally, supply and reliability related issues have surfaced throughout the state due to the growth in the economy and the age and inefficiency of some of the existing resources in the state. Given the increasing need for additional generation and reliability related resources, timely and supportive regulatory decisions remain key to the maintenance of HECO's credit quality.

4. Capital Programs for Utility Infrastructure Has Increased.

Capital expenditures for 2004 and 2005 exceeded $200 million annually and capital expenditures for 2006 are expected to be in a similar range. Most of the capital investment has been associated with transmission and distribution investments as well as new generation resources, all intended to meet growing demand and to improve reliability and supply options that exist on an aging electric system. HECO has also invested heavily in demand side management programs that are intended to reduce consumption and head off the need for additional peak time resources. Reflective of this capital investment requirement has been HECO's increase in operation and maintenance expense associated with their need to operate older, less efficient generation more frequently in order to satisfy higher demand requirements. HECO and its subsidiaries' ability to obtain timely and supportive regulatory treatment for its capital investment program remains an important rating consideration.

5. Concentration Risk

While HEI has two different business units to generate revenues, income and cash flow, its consolidated business fortunes are tied very closely to the Hawaiian economy and to events that impact the state, including weather related events and the potential for natural disasters. This is particularly relevant, given the state's isolated location and the company's modest size. In the end, this risk may prove to be difficult to mitigate and may be a limiting rating factor, particularly given the company's less than successful efforts several years ago to diversify its operations internationally.

Rating Outlook

HEI's stable rating outlook reflects an expectation that the company will continue to manage its growth in a conservative fashion, that timely regulatory support for the company's sizeable capital program will occur, and that management will remain focused around its current back-to-basics business strategy.

What Could Change the Rating - Up

In light of the sizeable capital investment programs at the utility and the uncertainty that surrounds associated rate case decisions and rate requests contemplated by HECO and its subsidiaries, limited near-term prospects exist for the rating to be upgraded.

What Could Change the Rating - Down

The rating could be downgraded should weaker than expected regulatory support emerge at HECO, including the continuation of regulatory lag, which ultimately causes earnings and sustainable cash flow to suffer.

Rating Factors

Hawaiian Electric Industries, Inc.

Select Key Ratios for Global Regulated Electric Utilities

Rating	Aa	Aa	A	A	Baa	Baa	Ba	Ba
Level of Business Risk	Medium	Low	Medium	Low	Medium	Low	Medium	Low
CFO pre-W/C to Interest (x) [1]	>6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
CFO pre-W/C to Debt (%) [1]	>30	>22	22-30	12-22	13-25	5-13	<13	<5
CFO pre-W/C - Dividends to Debt (%) [1]	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Total Debt to Book Capitalization (%)	<40	<50	40-60	50-70	50-70	60-75	>60	>70

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

commercial paper) and preferred stock rated by MOODY'S have, prior to assignment of any rating, agreed to pay to MOODY'S for appraisal and rating services rendered by it fees ranging from $1,500 to $2,400,000. Moody's Corporation (MCO) and its wholly-owned credit rating agency subsidiary, Moody's Investors Service (MIS), also maintain policies and procedures to address the independence of MIS's ratings and rating processes. Information regarding certain affiliations that may exist between directors of MCO and rated entities, and between entities who hold ratings from MIS and have also publicly reported to the SEC an ownership interest in MCO of more than 5%, is posted annually on Moody's website at www.moodys.com under the heading "Shareholder Relations - Corporate Governance - Director and Shareholder Affiliation Policy."

This credit rating opinion has been prepared without taking into account any of your objectives, financial situation or needs. You should, before acting on the opinion, consider the appropriateness of the opinion having regard to your own objectives, financial situation and needs.

DOD-IR-12

Please provide a complete transcription of the most recent analysts' earnings presentation made by Hawaiian Electric Industries.

<u>HECO Response:</u>

See pages 2 to 16 for this response for the complete transcription of the most recent analysts' earnings presentation made on May 4, 2007. Please note that although the complete transcription is being provided, the information on HEI and ASB is not relevant to this docket.

FINAL TRANSCRIPT

Thomson StreetEvents℠

HE - Q1 2007 Hawaiian Electric Industries, Inc. Earnings Conference Call

Event Date/Time: May. 04. 2007 / 2:00PM ET

CORPORATE PARTICIPANTS

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Connie Lau
Hawaiian Electric Industries, Inc. - President and CEO

Mike May
Hawaiian Electric Industries, Inc. - President & CEO, Hawaiian Electric Co

Tayne Sekimura
Hawaiian Electric Industries, Inc. - CFO, Hawaiian Electric Company

Eric Yeaman
Hawaiian Electric Industries, Inc. - CFO, HEI

CONFERENCE CALL PARTICIPANTS

Doug Fischer
AG Edwards - Analyst

David Parker
Robert W. Baird - Analyst

Paul Patterson
Glenrock Associates - Analyst

Steve Gambuzza
Longbow Research - Analyst

James Bellessa
DA Davidson - Analyst

PRESENTATION

Operator

Good day, Ladies and Gentlemen, and welcome to the Hawaiian Electric Industries 2007 first quarter earnings conference call. My name is Cami, and it will be my pleasure to be your coordinator today. At this time all participants are in a listen only mode. We will conduct a question and answer session toward the end of this conference. (OPERATOR INSTRUCTIONS). As a reminder this conference is being recorded for replay purposes.

I would now like to turn the presentation over to the Manager of Treasury and Investor Relations, Ms. Suzi Hollinger. Please proceed, ma'am.

Suzi Hollinger - *Hawaiian Electric Industries, Inc. - Manager, Treasury and IR*

Thank you, aloha and good afternoon. Thanks for joining us for an update on HEI. Here with me from Senior Management and speaking today are Connie Lau, HEI's and ASB's President and CEO, and Mike May, HECO President and CEO. Also on the call are are Eric Yeaman, HEI Financial Vice President, Treasurer and CFO, Financial Vice President and for HECO, Tayne Sekimura, and Alvin Sekimura, ASB, Executive Vice President, Finance. Connie will start the presentation with a few comments on first quarter earnings and then Mike will follow with an update on the utility. Connie will come back to discuss the bank and then we'll make some closing remarks. Upon conclusion of the presentation we'll open it up for your questions. Before I hand the call over to Connie I would like to alert you that forward-looking statements will be made on today's call. Please reference roman four of our first quarter form 10-Q that was filed this morning for information about forward-looking statements. Now let me turn the call over to Connie to begin the formal comments. Connie?

Connie Lau - *Hawaiian Electric Industries, Inc. - President and CEO*

Thanks, Suzi, and aloha to all of you.

As we stated in our year-end conference call in February, the challenges that we experienced in 2006 continued through the first quarter of 2007. Our utility continued to see rising operation and maintenance expenses, and our bank's earnings were impacted by a difficult interest rate environment and non-interest expenses remained high. These factors, combined with a $7 million net of tax write-off of capital costs related to our Keahole expansion project caused first quarter earnings to be down by $26 million or $0.32 per share when compared to the first quarter of 2006.

As you know, the write-off of the Keahole project cost was part of a settlement agreement with a consumer advocate in connection with our big island rate case. The financial details of the quarter were included in the earnings release that went out last night and in our form 10-Q that was filed this morning. I'll assume that most of you had a chance to read through the release, so I won't go through it, but we will be happy to answer any questions you have at the end of the formal presentation.

While the near term picture is challenging, the long term outlook for the Company remains positive and we are focusing our efforts on the key items that will drive long term earnings growth, namely rate relief at our utility and the bank's strategic transformation to a full service community bank. We recently received interim rate relief for our big island utility, which we began collecting in early April. Also, our utility moved one step closer to rate relief for its Maui subsidiary, when it filed a 2007 test year rate case for that service territory, in February. Our 2007 test year rate case for our Oahu utility was filed at the end of 2006. Mike will discuss the details of our rate cases when he updates you on the utility.

At the bank, we are working to offset net interest margin pressure by continuing to diversify the loan portfolio and maintaining and attracting low cost deposits and increasing non-interest income. Overall, we continue to operate our two core subsidiaries for long term earnings growth to support the dividend. Now, let me hand the call over to Mike to discuss the utility.

Mike May - *Hawaiian Electric Industries, Inc. - President & CEO, Hawaiian Electric Co*

Thanks, Connie. Aloha and good afternoon or good morning to some of you. As noted earlier, first quarter was a challenging one for us.

I'll spend most of my time today discussing those challenges and what we're doing to address them going forward. In the first quarter 2007, sales were up 0.6% over the same quarter in 2006. We expect this trend of moderate sales growth to continue. In 2007, 2008, and 2009, we are currently estimating sales to be moderately higher over the prior year by 0.6%, 1.6%, and 1.3% respectively.

Because of several years of economic growth in our State, overall demand for electricity has increased. This growth has caused a tightening of our generation reserve margins on Oahu and Maui during peak usage periods. As we've mentioned in previous calls, our O & M expenses have been rising as a result of running our units harder. This has required more extensive and frequent maintenance and repairs to our system. Also contributing to our rising O & M expenses are increased retirement benefit expenses. We expect these O & M levels to remain high.

To address the challenges, we are executing a strategic plan that focuses on making needed reliability investments and seeking recovery of costs through a rate case process. In line with a strategy over the next five years, we are focusing approximately $1.2 billion in gross capital expenditures to increase generation capacity and maintain an improved reliable electric service for our customers. This slide shows the anticipated utility capital expenditures by year. In recent years, we have been able to finance almost all of our capital expenditures with internal sources of funds. Although we still expect to finance the majority with internal sources, with our larger investment and reliability projects, we expect our borrowing levels to increase.

Our strategic plan includes seeking rate relief at all three utilities to cover these reliability investments and increased O & M expenses. As this chart illustrates, in April, we received an interim decision from the PUC for our HELCO rate case. Additionally we filed a rate case for MECO, our Maui county utility. We are encouraged by the timely interim decisions by the PUC on our rate cases. In our HECO 2005 case, we received an interim decision shortly after the evidentiary hearings were held and our HECO 2006 rate case, we received a prompt interim decision after filing our statement of probable entitlement. Over the next several slides, I will cover in greater detail the status and progress for each of these rate cases.

As Connie mentioned, for its 2006 rate case, our Hawaii Island utility, HELCO recently received a decision in April 2007 allowing for a $24.6 million or 7.58% increase in annual revenues. The interim P & L had reflects the terms of a settlement that we reached with a consumer advocate on the rate case. This includes an after-tax write-off of approximately $7 million of some plant and service costs for the Keahole project in the first quarter of 2007. The decision also includes pension assets and rate base and the restoration of book equity for rate making purposes. This reverses the decrease in HELCO's book equity that occurred at year-end when we recorded a charge to accumulated other comprehensive income to reflect the funded status of our retirement benefit plans at the end of 2006.

In addition, it approves a tracking mechanism for pension and other post-retirement benefit costs and a continuation of the energy cost adjustment clause. An evidentiary hearing is scheduled for May 2007. Again, we view this timely interim decision as an indication of regulatory support.

In December, we also filed a 2007 test year rate case for HECO on Oahu. We are requesting a $99.6 million, or 7.1% increase in revenues, with an 11.25% return on common equity. An interim decision is expected in late 2007.

In February of this year, we filed a rate case for our Maui County subsidiary, MECO, with 2007 test year. We are requesting $19 million or a 5.3% increase in revenues and an 11.25% return on common equity. Like the HELCO and HECO cases, this case proposes a tiered rate structure for encouraging energy efficiency. We expect an interim decision by early 2008.

We are awaiting for a final decision for our Oahu's 2005 rate case. There is no statutory deadline for the PUC to issue a final order. We continue to collect $41 million increase in our annual revenues as a result of the interim decision received earlier.

To sum up, a growing Hawaii economy has impacted our utilities reserve margins and from a financial perspective, our earnings. We expect this earnings pressure to continue in 2007. To address these challenges, we are increasing our capital expenditures, adding generation capacity, and other reliability investments. To recover increasing cost, we have several rate cases in progress with a focus on improving our earned rate of return. I want to emphasize that our plan will take several years and involve all three of our utilities. Over time, we look forward to an improvement in our earnings.

Now I'd like to turn things back to Connie to discuss the bank.

Connie Lau - *Hawaiian Electric Industries, Inc. - President and CEO*

Thanks, Mike.

For the bank, the first quarter was another tough quarter. High short-term interest rates, the shape of the yield curve, and high non-interest expenses impacted results for the quarter. In spite of the difficult interest rate environment, we are pleased by the performance of the bank's lines of business during the quarter and the improvement of the net interest margin over the prior quarter. Deposit rates and balances stabilized. Credit quality remains strong. Non-interest income continued to grow, and the bank's credit rating were upgraded by both major rating agencies.

During the quarter, our lending areas continued to perform well. Commercial loan balances grew by 9% during the quarter. Overall, growth in loan balances during the quarter was more modest, as the increases in residential and commercial loans were partially offset by lower commercial real estate and consumer loan balances. As we mentioned in previous quarters, we expected the decline in commercial real estate balances due to the scheduled pay off of several large construction loans. This, combined with our shift in emphasis back to income property lending contributed to the net decrease in commercial real estate balances.

First quarter net interest margin improved to 3.07% compared to 3.05% in the fourth quarter of 2006. This was in large part due to the fact that deposit balances were stable during the quarter. Equally important was the fact that we were able to accomplish this while holding deposit costs relatively steady, a change from the increasing deposit cost that we experienced throughout 2006. Managing deposit costs and retaining deposits will continue to be a challenge in the current interest rate environment.

Credit quality remains strong during the quarter due to the continued strength of the local economy. The health of the local residential real estate market remains good. Although transaction volumes have fallen off, prices have remained stable, and we have not experienced the declines in value or increases in foreclosures seen in many mainland markets. In a recent survey conducted by Royalty Track, Hawaii's foreclosure rate was among the lowest in the nation. In March in 2007, foreclosure activity in Hawaii ranked 43rd out of all the 50 states.

We are also pleased that our efforts to strengthen the bank through our strategic initiatives were recognized by both major rating agencies when they recently upgraded American Savings Bank's credit rating. Among the reasons cited for the ratings upgrades were the improvement in the bank's interest rate sensitivity and funding profiles, strong asset quality measures and good capital level. In particular, they noted that the bank's ability to manage its net interest margin through the current interest rate cycle was helped by the growth of commercial and commercial real estate loans, the growth of the deposit franchise, and the ability to control deposit costs, all core goals of the strategic transformation.

Our overall outlook has not changed since our previous call. We are expecting the difficult interest rate environment to persist through 2007, and do not expect significant relief from the pressure on net interest margin. Our expectations continue to be for modest growth in the loan portfolio, and we will continue to be challenged to grow deposits while managing deposit costs. Given the outlook for the Hawaii economy, credit quality is expected to remain good; however, factors such as significant growth in the loan portfolio, situations with specific borrowers or changes in outlook for the economy may cause credit costs to increase.

Recent results were impacted by higher non-interest expenses, primarily due to higher legal and litigation costs. While these costs may decline as matters are resolved, we expect overall non-interest expenses to remain near current levels. The bank has always had a focus on building sound infrastructures to support its transformation growth, and this year, we are strengthening our risk management and compliance infrastructure. Overall, we continue to believe that the adherence to our strategic plan has and will continue to help us manage through the current environment, and put the bank in the best position to grow and compete once the operating environment normalizes.

Now, let me wrap up the presentation with a few closing comments. First, a word about the dividend. You may have seen our dividend release yesterday announcing the Board's approval of a $0.31 per share dividend on our common stock. The dividend is payable on June 13th to shareholders of record on May 15th. Our dividend yield is attractive at 4.7%, and we expect to maintain the dividend.

In summary, while several key factors will continue to affect our core businesses in the near term, the long term outlook for our Company is positive. We expect the trend of rising utility O & M expenses to continue and that utility returns will improve when rate relief is received. As Mike discussed, rate cases have been filed for all service territories and we are beginning to see some interim rate relief. At the banks, the difficult interest rate environment will continue to put pressure on net interest margins. Economists believe the environment should improve later this year, and if so, that could take some of the pressure off our net interest margin. With respect to the dividend, we intend to maintain the dividend through these near term challenges and are focused on the key strategies that will drive long term earnings growth.

This concludes our formal comments, and we'll be happy to answer any questions you may have.

QUESTIONS AND ANSWERS

Operator

Thank you. (OPERATOR INSTRUCTIONS) And your first question comes from the line of Doug Fischer with A.G. Edwards. Please go ahead.

Doug Fischer - *AG Edwards - Analyst*

Aloha.

Connie Lau - *Hawaiian Electric Industries, Inc. - President and CEO*

Hi, Doug.

Doug Fischer - *AG Edwards - Analyst*

Hello, Connie and company. Two questions about expenses. Utility O & M was up, we were expecting it to be up quite frankly it was up more than we might have expected in the first quarter. When you say expenses are going to remain high, should we be looking for similar percentage increases in future quarters, or is there some timing issue in this first quarter that might result in lesser percentage increases through the balance of the year?

Mike May - *Hawaiian Electric Industries, Inc. - President & CEO, Hawaiian Electric Co*

Doug, this is Mike. As we have been saying for the last several calls, we expect that our O & M expenses will continue to be at a high level until we get the additional capacity that we've been talking about as we've indicated, we've been short of reserve margins, and we're having to run our units harder. We're having to do more extensive work and that continues to be our plight until we get the 2009 unit in place and the additional capacities that we have scheduled for the neighbor islands as well, particularly Maui.

Doug Fischer - *AG Edwards - Analyst*

And what kind of, maybe you can talk to us a little bit about the overhauls, what kind of cycle they're on and whether there's any lumpiness to it during the year?

Mike May - *Hawaiian Electric Industries, Inc. - President & CEO, Hawaiian Electric Co*

Well, the only lumpy comparison I can make is if you compare the first quarter of '06 with the first quarter of '07, there's always a change in mix. The one example I can cite is that AES had an overhaul in the first quarter of 06, which basically did not allow us to do overhauls in our units, so AES was not doing an overall in the first quarter of '07, which gave us the opportunity to do extensive overhauls on some of our units, so those kind of things occur from time to time in the business.

Doug Fischer - *AG Edwards - Analyst*

Is there any guidance you can give us for the balance of the year as to the timing of overhauls versus what you had in the first quarter?

Mike May - *Hawaiian Electric Industries, Inc. - President & CEO, Hawaiian Electric Co*

The only thing I can tell you is that we will continue to make decisions around reliability and supporting the energy needs, and what we are working on in tandem with that is the rate case cycle to adequately recover the O & M cost and the capital investments that we're making to support that.

Doug Fischer - *AG Edwards - Analyst*

And then at the bank, the services expenses were up materially, and I guess was the bulk of that these legal and litigation expenses?

Connie Lau - *Hawaiian Electric Industries, Inc. - President and CEO*

Yes, that's correct, Doug.

Doug Fischer - *AG Edwards - Analyst*

Could you provide some color around those? Were those abnormally high? I know you said that relatively high levels are going to continue.

Connie Lau - *Hawaiian Electric Industries, Inc. - President and CEO*

Yes. The legal and litigation expenses were at an abnormally high level, and as I said in my prepared remarks, as those matters get resolved, we may see those costs come down; however, we have always had a philosophy of investing in the transformation and in the infrastructure necessary to support the transformation and you'll recall that often that services line has included significant consulting expenses and we would expect that the overall non-interest expense will remain at a relatively high level because this year, we're working on our risk management and compliance infrastructure.

Doug Fischer - *AG Edwards - Analyst*

Okay, thank you.

Operator

Your next question comes from the line of Dave Parker with Robert W. Baird. Please proceed.

David Parker - *Robert W. Baird - Analyst*

Good morning and thanks for letting my call come through. Doug as usual took all the good questions so let me see if I can ask a few B ones. First off, an interesting component of the HELCO settlement was the, I guess for better terms call it sort of a tracker on retirement cost. If that was applied to all of the three utility systems, how could that help earnings performance I guess if I could try to put it in that context.

Tayne Sekimura - *Hawaiian Electric Industries, Inc. - CFO, Hawaiian Electric Company*

Dave, this is Tayne Sekimura. Hi, I'm going to respond to your question there. Again, I just want to remind everyone that the pension tracking mechanism was something that was included in the HELCO interim decision. If it were applied to the HECO and MECO cases, what the tracking mechanism allows for are changes outside of test year rate cases, changes in pension costs to be captured in a holding account and be booked at either a regulatory asset or a regulatory liability and that the next rate case become part of that case and brought into the pension cost for that test year.

David Parker - *Robert W. Baird - Analyst*

Great. And any recollection, Tayne, on how much that's been a drag on earnings? Want to stick your neck out a little bit on that one? That could give us hopefully in 2008 if we got that applied with how much we could pick up on that?

Eric Yeaman - *Hawaiian Electric Industries, Inc. - CFO, HEI*

Dave, this is Eric. For the change between 06 and '07, it's about 2.5 million.

David Parker - *Robert W. Baird - Analyst*

Great. Thanks, Eric. Second question, I know it was really wet a year ago and vegetation control costs spiked substantially. Are we going to see any relief there, Mike, when we look at just maintenance costs year-over-year this year's comparison or does that remain pretty high?

Mike May - *Hawaiian Electric Industries, Inc. - President & CEO, Hawaiian Electric Co*

Dave, the reports that I'm getting from operations continue to speak to the need for vegetation management. Some of our folks just did a flyover of the system and the report that I received is that there's continuing vegetation management in our corridors that needs to occur.

David Parker - *Robert W. Baird - Analyst*

Okay, and it looked as if weather was probably in your favor yet. I didn't see that quite translate into sales growth as I expected. Is conservation or demand side management efforts that you've been aggressively going after helping here to keep the low growth at minimal levels?

Mike May - *Hawaiian Electric Industries, Inc. - President & CEO, Hawaiian Electric Co*

We believe the Company has launched a very conscious and aggressive effort through a combination of conservation initiatives and demand side management, energy efficiency programs. We have implemented with the Public Utilities Commission support a number of both commercial and industrial demand side management programs, energy efficiency programs, and we've had additional support from the Public Utilities Commission to expand those programs and to further extend the effect of that on our system.

Of course, the benefit of that is it's a lot cheaper to save a kilowatt than it is to generate one, and the trueup time is obviously in the rate case when you try to balance out against the offset. There was, in the energy efficiency as you may recall the 2005 docket, our rate case was bifurcated and there was a separation of the rate case from the energy efficiency docket, and the PUC has continued to allow us to participate and also have a tiered reward system, if you will, as a result of that decision. So to answer your question more succinctly, there is some efficiency and conservation that are a product of our aggressive efforts and programs.

David Parker - *Robert W. Baird - Analyst*

Is there any mismatch right now, Mike, between expenses and revenues collected or is that, are we experiencing any regulatory lag or are we pretty current on that?

Mike May - *Hawaiian Electric Industries, Inc. - President & CEO, Hawaiian Electric Co*

I think to answer your question, I don't think so.

David Parker - *Robert W. Baird - Analyst*

Okay. All right, thank you. Over to the Bank, maybe you could refresh my recollection, but the slowdown in the commercial real estate lending activity that's not by accident, wasn't that pretty much by design from my understanding?

Connie Lau - *Hawaiian Electric Industries, Inc. - President and CEO*

Yes. Dave, you'll recall that in the commercial real estate line of business, it tends to be pretty cyclical according to the economy, and you actually have to be quite anticipatory and look out 2-3 years, particularly when you're doing construction projects, because it takes about two to three years from the time you first commit to make the loans to when approvals are received, construction actually begins, and we start funding those loans and products is delivered, and so actually, about a year and a half ago, we had started shifting our emphasis away from the construction lending area to income property lending, and so what's happening now is the construction loans that we made two years ago are starting to finish up those projects or delivering their product now to the buyers and so they're getting paid down, so yes, you're correct, and we will continue to see that through the year. We are looking to make up that volume through the emphasis on the income property lending and also through our commercial banking line of business.

David Parker - *Robert W. Baird - Analyst*

Great. That's what I thought, and I know you're trying to fix the yield curve and good luck there, but --

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Connie Lau - *Hawaiian Electric Industries, Inc. - President and CEO*

Can you help us out on that, Dave?

David Parker - *Robert W. Baird - Analyst*

I've tried. I've done everything I can. I'll leave it to the experts. And also, home values are hanging right in there in Hawaii and I think last call, you identified the average price of a home was pretty high. Could you refresh my memory, because obviously this has an important impact on just the allowance that you don't have to take is for the values to hang in there, why have home prices done so well in Hawaii?

Connie Lau - *Hawaiian Electric Industries, Inc. - President and CEO*

Yes. It's really still, I mean, we are islands, and it takes awhile for approvals to be obtained on residential projects, and so our developers here try to watch the market pretty carefully in terms of balancing that off and so you're correct. The housing prices really have held in there and actually demand is still pretty strong. Now, we are seeing some differences across the islands. Certain markets are weakening somewhat, but overall, while the transaction volumes have been slowing, the prices really have been very stable.

David Parker - *Robert W. Baird - Analyst*

Okay, good. And I just thought of one other question, back at the utility, with rate cases sort of pancaking up here and increases are anywhere from 5 to 6 to 7% a shot, are you starting to see any impact from rate payors or negative editorials, that kind of stuff where we get a sense of a rate payer result starting to line up?

Mike May - *Hawaiian Electric Industries, Inc. - President & CEO, Hawaiian Electric Co*

To answer your question, Dave, we've not seen any indications of that at all. The process that we go through is before an application, after an application is filed, there are actually public comments sessions that are conducted by the Public Utilities Commission, and I think for the most part in all of our public comment sections or hearings, there has been little in the way of opposition.

David Parker - *Robert W. Baird - Analyst*

Great. Thank you.

Operator

Your next question comes from the line of Paul Patterson with Glenrock Associates. Please go ahead.

Paul Patterson - *Glenrock Associates - Analyst*

Hi. Almost all my questions have been answered. Just one sort of follow-up on the shifting out of the construction loans to the income property loans, what is it that you guys are anticipating I guess specifically happening that's causing you guys to take that action now?

Connie Lau - *Hawaiian Electric Industries, Inc. - President and CEO*

Just actually, Paul, we started taking that about two years ago, just the normal slowing of the cycle, and so while the cycle has slowed, actually as I've just stated, the housing prices are just hanging in there, and so what's happened with the Hawaii market is that we were really pretty much on fire after 9-11, there was a little dip, and then our economy really was quite strong, and many people really began to see Hawaii, particularly in the resort areas and the neighbor islands as really safe place to have a second, third, or fourth home, and so our real estate market has been very very strong, and we are coming off that very strong peak, and that's what we were foreseeing a couple of years ago when we made that strategy shift to emphasize the income property lending as we saw that construction might flow.

Paul Patterson - *Glenrock Associates - Analyst*

Right, but in other words, you guys were, the demand for construction loans has simply been falling. There hasn't been, you guys aren't actually shifting, is it because there's less demand for the construction loans or is it because you guys feel that the quality of those loans might be in question I guess?

Connie Lau - *Hawaiian Electric Industries, Inc. - President and CEO*

Yes. Actually, demand for loans is still quite strong. It's more a strategy shift on our part that we want to put the income property loans into our portfolio at this point in the cycle. We are still doing construction lending but I think as we said when we first began doing the construction lending, we really only do selected construction lending.

Paul Patterson - *Glenrock Associates - Analyst*

Okay. Thanks a lot, guys.

Connie Lau - *Hawaiian Electric Industries, Inc. - President and CEO*

Yes..

Operator

Your next question comes from the line of Steve Gambuzza with long bow capital. Please proceed.

Steve Gambuzza - *Longbow Research - Analyst*

Hi. I was wondering if you could just review the issue of prepaid pension asset and rate base if you wouldn't mind just kind of going through each of the utilities where you have, how much of prepaid pension asset you have on the balance sheet and how much you are seeking to get into rate base and what the status of that request is.

Tayne Sekimura - *Hawaiian Electric Industries, Inc. - CFO, Hawaiian Electric Company*

This is Tayne Sekimura. Right now, because of the charge we took for AOCI as of 12 -31-06, we don't have a prepaid pension asset on our balance sheet. That was the result of implementing FAS 158 on how we account for our pension costs. So right now, nothing on the balance sheet.

Steve Gambuzza - *Longbow Research - Analyst*

Okay. How about in rate base?

Tayne Sekimura - *Hawaiian Electric Industries, Inc. - CFO, Hawaiian Electric Company*

But in terms from a regulatory perspective, we have included that amount in our rate base, and just as a reminder, the prepaid pension asset is really the result of an accumulation of all your expenses over the years and how much we've contributed to the fund, and there for, we do require a return on that asset and have included it in rate base, in our rate cases. Okay can you just review for each utility how much is in rate base? Can I come back to that question?

Steve Gambuzza - *Longbow Research - Analyst*

Sure.

Tayne Sekimura - *Hawaiian Electric Industries, Inc. - CFO, Hawaiian Electric Company*

I'll check that right now.

Connie Lau - *Hawaiian Electric Industries, Inc. - President and CEO*

While Tayne looks at that number let me just add something to Paul's question on the whole construction cycle. In our commercial real estate line of business, what we really do is try to follow the cycles really to anticipate the cycles in the real estate market, and so for example, on the construction lending side is part of the market that we began looking at whether we should shift emphasis is really the residential because we were having a lot of residential construction, so as I mentioned, we are still doing selected construction lending and right now, in fact we're looking at a large retail complex, so our construction lending will shift according to the cycles here in the market because we really, as it was said earlier, have to be anticipatory ust as our customers have to be as to where the market will be two or three years out for these projects when the product will actually deliver. I'll see if Tayne has her answer.

Tayne Sekimura - *Hawaiian Electric Industries, Inc. - CFO, Hawaiian Electric Company*

Yes, I do. The amounts and these are approximate amounts that we have in rate base, for the prepaid pension item, for HECO, it's about $60 million. For HELCO, it's $12 million and for MECO, it's $3 million.

Steve Gambuzza - *Longbow Research - Analyst*

3 million you said?

Tayne Sekimura - *Hawaiian Electric Industries, Inc. - CFO, Hawaiian Electric Company*

Yes.

Steve Gambuzza - *Longbow Research - Analyst*

And those amounts have all been approved and regulatory filings or they are requests?

Connie Lau - *Hawaiian Electric Industries, Inc. - President and CEO*

No. For the HELCO case, that has been included in its interim but for HECO and for MECO, they are included in our request, and those cases are still pending.

Steve Gambuzza - *Longbow Research - Analyst*

Okay.

Tayne Sekimura - *Hawaiian Electric Industries, Inc. - CFO, Hawaiian Electric Company*

And ongoing.

Steve Gambuzza - *Longbow Research - Analyst*

Thank you and finally just want to understand the issue of what's going to happen from a GAAP standpoint on the prepaid pension asset? Is it you wrote it off last quarter and now you've been authorized to reestablish that asset and so you're going to take that back to equity?

Connie Lau - *Hawaiian Electric Industries, Inc. - President and CEO*

Yes. Let me explain that. The prepaid pension tracking mechanism allows us reverse the charge that we took to equity and establish a regulatory asset, that's for the HELCO case. Assuming that a similar tracking mechanism is approved for HE CO and MECO that will allow us reverse the charge that was taken as of December 2006.

Steve Gambuzza - *Longbow Research - Analyst*

Okay and when would you expect to have at least interim orders on those two cases?

Connie Lau - *Hawaiian Electric Industries, Inc. - President and CEO*

Well on the HECO case, we expect an interim later in 2007 and for the MECO Maui case, we do expect an interim some time in early 2008.

Steve Gambuzza - *Longbow Research - Analyst*

And are there any like I guess my question would be are there any differences in the requests on this issue for the three utilities or the facts and circumstances are essentially the same such as if the Commission chooses to apply a similar logic you'd expect a similar decision you got in HELCO for the other two utilities?

Connie Lau - *Hawaiian Electric Industries, Inc. - President and CEO*

Well on our positions we are going to take similar positions for the Company. The Commission still needs to go through its process of evaluating each utility separately, and so we do need to see what they will say in each of those cases separately.

Steve Gambuzza - *Longbow Research - Analyst*

Okay, thanks very much.

Operator

(OPERATOR INSTRUCTIONS) Your next question comes from the line of James Bellessa with D.A. Davidson & Company. Please go ahead.

James Bellessa - *DA Davidson - Analyst*

Afternoon.

Connie Lau - *Hawaiian Electric Industries, Inc. - President and CEO*

Hi, James.

James Bellessa - *DA Davidson - Analyst*

It seems to me that you've seen this struggle that you're facing right now in the utility for a long time, and I'm wondering why you didn't start earlier in trying to build new plant and equipment and get rate basing or is it a situation where you have to be hemorrhaging in that state before you get adequate rate relief?

Mike May - *Hawaiian Electric Industries, Inc. - President & CEO, Hawaiian Electric Co*

Jim, This is Mike. Good question. We have actually had in our plans for a number of years to add generation. We have known since 2002 that we had the need. We've had the applications and the process under way, and it just takes awhile to site and build a power plant in Hawaii. That's also true I think probably for most utilities around the country. Siting, infrastructure whether it be transmission or generation assets have a higher level of scrutiny and involvement by everyone from the community to the regulators, all of the environmental it's and that is probably more indicative of our times than it is unique to Hawaii.

James Bellessa - *DA Davidson - Analyst*

When you get the new plant and equipment up and running, will you not still have this older plant and need it as part of your core assets and therefore, you still have O & M expenses on it?

Mike May - *Hawaiian Electric Industries, Inc. - President & CEO, Hawaiian Electric Co*

Well, keep in mind, Jim, that the real crunch that we are experiencing isn't during our peak period. We don't have a problem over our normal load. It's in the peak period so this 2009 unit is actually a peeking unit, so what we're having to do is keep all of our units because of the tight reserve margin during peak period that the finest level of reliability as we possibly can, hence the O & M expenses. When we get the peaking unit in 2009, it should provide some relief from that situation we find ourselves in.

James Bellessa - *DA Davidson - Analyst*

Thank you very much.

Operator

And at this time we have no more questions in queue. I would now like to turn the call back over to Ms. Suzi Hollinger for closing remarks.

Suzi Hollinger - *Hawaiian Electric Industries, Inc. - Manager, Treasury and IR*

Thanks, everyone for participating on the call. If you have further questions please call me at 808-543-7385. Aloha.

Operator

Thank you for attending today's conference. This concludes the presentation. You may now disconnect and have a great day.

DOD-IR-13

Please provide a complete, detailed copy of Hawaiian Electric Industries' most recent bond rating agency presentation (i.e., not a slide-show summary, but the volume that discusses in detail the Company's operations, generation, transmission assets, purchased power contracts, financial projections and service territory economics.). Also please consider this an on-going request, so that, if the Company made a presentation in 2006 and makes another presentation during the pendency of this rate proceeding, the Company will provide both presentations.

HECO Response:

As noted in HECO's response to CA-IR-12, HECO objects to providing the presentations by HEI and its subsidiaries to the rating agencies on the grounds that the presentations contain privileged commercial and financial information (including earnings forecast information), which is maintained by HEI, its subsidiaries and the rating agencies as non-public, confidential information, and on the grounds that those portions of the presentations related to HEI and its non-utility subsidiaries are irrelevant to the issues in this proceeding. Without waiving its objection, the Company submits the May 2007 presentation to rating agencies relating to the utilities pursuant to Protective Order No. 23378. HECO objects to making available forecast earnings and forecast return information, which disclosure might trigger requirements under rules and guidelines of the Securities and Exchange Commission and/or the New York Stock Exchange (see discussion in HECO's response to CA-IR-8) and customer information due to privacy concerns, even under protective order.

In addition, information in presentations to rating agencies related to HEI and its non-utility subsidiaries is not relevant to the issues in this docket. While HEI is the parent of HECO, the Commission generally has ruled that HEI, as a diversified holding company, is not an appropriate proxy for HECO or its utility subsidiaries in determining their cost of capital. (See

Decision and Order No. 11317 in Docket No. 6531 (HECO's 1990 Test Year) and Decision and Order No. 10993 in Docket No. 6432 (HELCO's 1990 Test Year).)

Pages 3 to 35 contain confidential information and are being provided pursuant to Protective Order No. 23378, issued on April 23, 2007.

DOD-IR-14

a) Please provide the monthly short-term debt balances for Hawaiian Electric Industries, Inc. and Hawaii Electric Company for each month from January 2004 through the most recent month available. Please explain how the monthly short-term debt balance is calculated (e.g., month-ending balance, average daily balance), and provide a sample calculation.

b) Please provide, for each month, the monthly cost-rate of that short-term debt for Hawaiian Electric Industries and separately for Hawaiian Electric Company, and a sample calculation showing how that monthly cost rate is derived.

c) Please provide a narrative description of Hawaiian Electric Industries' short-term debt financing arrangements, as well as inter-company borrowing arrangements between Hawaiian Electric Industries subsidiaries.

HECO Response:

a) Please see the schedules on pages 4 to 5. The short-term balances are month-ending balances. HECO's (Oahu only) short-term debt shown on page 4 are comprised of commercial paper issuances (net of unamortized discount, if any) and any intercompany borrowings from HEI, HELCO and/or MECO, net of any advances to HELCO and/or MECO. HEI's short-term debt shown on page 5 are the consolidation of HECO Consolidated short-term borrowings (net of any intercompany borrowings) and HEI's commercial paper, net of unamortized discount. HECO objects to providing the April 2007 month-ending balance for HECO (Oahu only) on the grounds that the month-ending balance is privileged commercial and financial information which is maintained as non-public, confidential information until released publicly in the SEC filings 10-Q or 10-K. HECO also objects to providing HEI's monthly short-term balances for non-quarter ending months on the grounds that the non-quarter ending monthly information is privileged commercial and financial information which is maintained as non-public, confidential information. Without waiving its objections, the Company submits the confidential information on pages 4 and 5 pursuant to Protective Order No. 23378.

b) HECO and HEI do not calculate the embedded cost of short-term debt. See discussion in HECO's response to DOD-IR-6(c).

c) HEI can negotiate and enter into short-term borrowings, including the sale of commercial paper, drawings under bank lines of credit and other short-term corporate loans, up to the Board-approved amount outstanding at any one time, with one or more banks, other financial or commercial institutions or other affiliated (intercompany) or nonaffiliated sources.

The objective of intercompany borrowing and investment is to make efficient use of funds available from affiliated companies while meeting the cash needs of the companies and to take advantage of the economies of scale in external borrowings and investing. When subsidiaries need funds, HEI will loan excess cash to its subsidiaries or may borrow from external sources to meet subsidiary cash needs.

In managing its cash requirements, HECO may borrow from HEI. If HECO borrows from HEI, HECO is charged either:

- the lower of HEI's and HECO's effective weighted average short-term external borrowing rate if both HEI and HECO had external borrowings outstanding during the month; or

- the lower of HEI's effective weighted average short-term external borrowing rate and the average of the effective rate for 30-day dealer-placed commercial paper quoted by the Wall Street Journal on each Friday during the month, plus fifteen basis points (0.15%) if only HEI had external borrowings outstanding during the month; or

- HECO's effective weighted average short-term external borrowing rate if only HECO had external borrowings outstanding during the month; or
- the average of the effective rate for 30-day dealer-placed commercial paper quoted by the Wall Street Journal on each Friday during the month, plus fifteen basis points (0.15%) if both HEI and HECO had no external borrowings outstanding during the month;

plus borrowing and transaction costs.

Although HECO may loan funds to HEI with prior PUC approval, it is HEI's and HECO's policy that HECO may not loan funds to HEI.

Confidential Information
Deleted Pursuant to
Protective Order No. 23378

DOD-IR-14
DOCKET NO. 2006-0386

HECO (Oahu only) Short-Term Debt
Month-End Balances
($ in thousands)

	2007	2006	2005	2004
Jan	57,920	91,093	73,957	14,700
Feb	83,244	94,714	85,853	42,537
Mar	4,942	96,307	79,520	41,492
Apr		94,130	88,563	63,302
May		105,102	87,096	58,492
Jun		106,876	91,841	63,513
Jul		105,917	76,201	50,902
Aug		88,637	91,152	36,717
Sep		83,430	94,801	51,972
Oct		73,487	92,959	57,828
Nov		40,395	83,785	56,698
Dec		58,707	91,715	61,460

Confidential Information
Deleted Pursuant to
Protective Order No. 23378

HEI Short-Term Debt
Month-End Balances
($ in thousands)

	2007	2006	2005	2004
Jan				
Feb				
Mar	123,414	182,584	100,107	22,992
Apr				
May				
Jun		296,493	126,888	14,197
Jul				
Aug				
Sep		194,211	120,642	8,392
Oct				
Nov				
Dec		176,272	141,758	76,611

NOTE: The quarter-end balances are presented in SEC filings 10-Q and 10-K.

DOD-IR-15

Please provide an income statement for Hawaiian Electric Company at the end of each fiscal year over the past ten years.

<u>HECO Response:</u>

See pages 2 to 23 for the December income statements that were filed with the Public Utilities Commission for the last ten years.

HAWAIIAN ELECTRIC COMPANY, INC
MONTHLY FINANCIAL REPORT
DECEMBER 1997

TO THE PUBLIC UTILITIES COMMISSION OF THE STATE OF HAWAII
COMPARATIVE ANALYSIS OF INCOME AND RETAINED EARNINGS

		THIS MONTH	ACCUMULATED TOTALS CURRENT YTD	ACCUMULATED TOTALS PRIOR YTD	INC-DEC ACCUM TOTALS
	UTILITY OPERATING INCOME				
400.0	OPERATING REVENUES (Page 5)	65,352,676	784,688,314	772,447,602	12,240,712
	OPERATING EXPENSES				
401/2	OPERATING & MAINT EXPS (Page 6)	46,100,760	551,361,673	542,104,649	9,257,025
403.0	DEPRECIATION EXPENSE	4,710,345	55,925,127	50,959,735	4,965,392
404.0	AMORT OF UTILITY PLANT	59,449	713,392	531,206	182,186
403.2	AMORT CONT IN AID OF CONSTR	(464,869)	(5,706,127)	(5,391,047)	(315,080)
406.0	AMORT OF UTIL PLANT ACQ ADJ	0	0	0	0
408.1	TAXES OTHER THAN INC TAXES	6,455,719	74,112,151	72,839,388	1,272,763
409.1	INCOME TAXES	1,188,009	32,161,525	35,850,142	(3,688,617)
410.1	PROV FOR DEF INCOME TAXES	1,497,781	(999,118)	(2,883,859)	1,884,741
412.1	PROV FOR DEF INVEST TAX CR	(159,815)	1,478,381	2,023,369	(544,988)
411.1	INC TAXES DEF IN PRIOR YRS-CR	206,476	1,544,540	1,328,180	216,360
412.2	AMORT OF DEF INVEST TX CR-CR	(46,749)	(593,982)	(598,179)	4,197
	TOTAL OPERATING EXPENSES	59,547,107	709,997,562	696,763,584	13,233,978
	OPERATING INCOME	5,805,568	74,690,752	75,684,019	(993,266)
	INC FROM UTIL PLANT-LEASED OT	0	0	0	0
	TOTAL OPERATING INCOME	5,805,568	74,690,752	75,684,019	(993,266)
	OTHER INCOME				
	INC FROM MDSE, JOBBING, CON WK	0	0	0	0
415-17	INC FROM NON-UTIL OPERATIONS	48,185	356,591	(185,384)	541,976
418.0	NON-OPERATING RENTAL INCOME	0	0	0	0
419.0	INTEREST & DIVIDEND INCOME	235,538	3,884,504	5,391,856	(1,507,351)
420.0	ALLOW FOR FUNDS USED-CONSTR	575,839	6,549,193	6,701,633	(152,440)
421/22	MISC NON-OPERATING INCOME	262,517	2,666,687	2,787,792	(121,105)
421.1	UNDISTR EARNINGS OF SUBS	1,727,189	28,617,887	29,417,645	(799,758)
	TOTAL OTHER INCOME	2,849,268	42,074,862	44,113,541	(2,038,679)

TO THE PUBLIC UTILITIES COMMISSION OF THE STATE OF HAWAII
COMPARATIVE ANALYSIS OF INCOME AND RETAINED EARNINGS

		THIS MONTH	ACCUMULATED TOTALS CURRENT YTD	PRIOR YTD	INC-DEC ACCUM TOTALS
	OTHER INCOME DEDUCTIONS				
408.2	OTHER TAXES ON OTH INCOME	11,660	60,757	8,103	52,654
409.2*	INCOME TAXES ON OTH INCOME	(36,507)	(179,058)	(225,774)	46,716
425/26	MISC INCOME DEDUCTIONS	137,272	576,396	687,677	(111,281)
	TOTAL OTHER INCOME DEDUCTIONS	112,424	458,095	470,006	(11,912)
	INTEREST CHARGES				
427.0	INTEREST ON LONG-TERM DEBT	2,053,746	24,268,393	23,646,050	622,343
428.0	AMORT OF DEBT DISC & EXPENSE	75,267	871,165	894,409	(23,244)
429.0	AMORT OF PREMIUM ON DEBT-CR	0	0	0	0
430.0	INTER ON DEBT TO ASSOC COS	233,499	2,411,675	288,805	2,122,869
431.0	OTHER INTEREST EXPENSE	499,375	6,907,594	9,285,297	(2,377,703)
	TOTAL INTEREST CHARGES	2,861,886	34,458,827	34,114,561	344,266
	INCOME BEFORE EXTRAORD ITEMS	5,680,526	81,848,693	85,212,993	(3,364,299)
	EXTRAORDINARY ITEMS (NET)	0	0	0	0
	NET INCOME	5,680,526	81,848,693	85,212,993	(3,364,299)
	RETAINED EARNINGS (BEG OF PER)	399,061,800	367,769,778	343,424,884	24,344,894
435.0	BALANCE TRANSFERRED FROM INC	5,680,526	81,848,693	85,212,993	(3,364,299)
439.0	ADJ TO RETAIN EARN	0	0	0	0
437.0	DIVIDENDS DECLAR-PREF STOCK	304,234	3,659,379	3,865,099	(205,720)
438.0	DIVIDENDS DECLAR-COM STOCK	16,856,000	58,377,000	57,003,000	1,374,000
	RETAINED EARNINGS (END OF PER)	387,582,092	387,582,092	367,769,778	19,812,315

* ALSO INCLUDES ACCOUNTS 410.2 AND 411.2.

FSR/507R

HAWAIIAN ELECTRIC COMPANY, INC.
MONTHLY FINANCIAL REPORT
DECEMBER 1997

TO THE PUBLIC UTILITIES COMMISSION OF THE STATE OF HAWAII
ANALYSIS OF OPERATING EXPENSES

		TOTALS FOR		ACCUMULATED TOTALS		INCREASE-DECREASE ACCUM. TOTALS
		THIS MONTH	SAME MONTH LAST YEAR	THIS YEAR	SAME PERIOD LAST YEAR	
	PRODUCTION EXPENSES:					
	Steam Power Generation					
500/07	Operation	14,636,697	16,528,841	185,830,059	179,820,209	6,009,850
510/14	Maintenance	1,397,942	2,956,946	16,615,348	16,005,115	610,233
	Other Pwr/Fuel Generation					
546/50	Operation	21,031	21,709	354,367	316,996	37,371
551/54	Maintenance	7,006	25,109	57,661	142,101	(84,441)
555/57	Other Purch. Pwr Expenses	21,516,184	21,419,443	252,863,558	248,085,480	4,778,078
	TRANSMISSION EXPENSES:					
560/67	Operation	366,749	392,282	3,630,983	3,320,012	310,971
568/72	Maintenance	346,524	884,225	3,560,348	5,346,504	(1,786,157)
	DISTRIBUTION EXPENSES:					
580/89	Operation	739,026	688,587	7,707,788	7,834,290	(126,502)
590/98	Maintenance	1,066,542	1,228,007	9,734,464	8,972,616	761,848
901/05	CUSTOMER A/C EXPENSES:	907,628	880,786	9,626,795	10,249,232	(622,437)
909/12	CUST. SERVICE EXPENSES:	1,114,430	933,258	9,272,011	5,030,610	4,241,402
	ADMINISTRATIVE & GENERAL:					
920/31	Operation	3,823,327	5,848,049	51,058,514	55,691,067	(4,632,554)
932.0	Maintenance	157,675	461,920	1,049,779	1,290,416	(240,638)
	TOTAL OPERATING EXPENSES	46,100,760	52,269,163	551,361,673	542,104,649	9,257,025
401	Total Operation Expenses	43,125,072	46,712,955	520,344,074	510,347,895	9,996,179
402	Total Maint. Expenses	2,975,688	5,556,208	31,017,600	31,756,753	(739,154)

HAWAIIAN ELECTRIC COMPANY, INC
MONTHLY FINANCIAL REPORT
DECEMBER 1998

TO THE PUBLIC UTILITIES COMMISSION OF THE STATE OF HAWAII
COMPARATIVE ANALYSIS OF INCOME AND RETAINED EARNINGS

			ACCUMULATED TOTALS		INC-DEC
		THIS MONTH	CURRENT YTD	PRIOR YTD	ACCUM TOTALS
	UTILITY OPERATING INCOME				
400.0	OPERATING REVENUES (Page 5)	61,014,720	716,841,314	784,688,314	(67,847,000)
	OPERATING EXPENSES				
401/2	OPERATING & MAINT EXPS (Page 6)	44,185,812	484,445,893	551,361,673	(66,915,780)
403.0	DEPRECIATION EXPENSE	4,897,491	58,008,745	55,925,127	2,083,618
404.0	AMORT OF UTILITY PLANT	49,389	592,665	713,392	(120,727)
403.2	AMORT CONT IN AID OF CONSTR	(491,953)	(5,787,694)	(5,706,127)	(81,567)
406.0	AMORT OF UTIL PLANT ACQ ADJ	0	0	0	0
408.1	TAXES OTHER THAN INC TAXES	5,811,730	67,426,683	74,112,151	(6,685,468)
409.1	INCOME TAXES	(1,209,202)	31,569,606	32,161,525	(591,919)
410.1	PROV FOR DEF INCOME TAXES	3,085,346	(1,031,991)	(999,118)	(32,873)
412.1	PROV FOR DEF INVEST TAX CR	(47,467)	1,815,930	1,478,381	337,550
411.1	INC TAXES DEF IN PRIOR YRS-CR	184,747	3,398,398	1,544,540	1,853,858
412.2	AMORT OF DEF INVEST TX CR-CR	(54,484)	(648,731)	(593,982)	(54,749)
	TOTAL OPERATING EXPENSES	56,411,410	639,789,505	709,997,562	(70,208,057)
	OPERATING INCOME	4,603,311	77,051,809	74,690,752	2,361,057
	INC FROM UTIL PLANT-LEASED OT	0	0	0	0
	TOTAL OPERATING INCOME	4,603,311	77,051,809	74,690,752	2,361,057
	OTHER INCOME				
	INC FROM MDSE, JOBBING,CON WK	0	0	0	0
415-17	INC FROM NON-UTIL OPERATIONS	(32,281)	90,216	356,591	(266,376)
418.0	NON-OPERATING RENTAL INCOME	0	0	0	0
419.0	INTEREST & DIVIDEND INCOME	241,855	2,898,076	3,884,504	(986,428)
420.0	ALLOW FOR FUNDS USED-CONSTR	577,613	7,204,789	6,549,193	655,596
421/22	MISC NON-OPERATING INCOME	146,326	2,847,626	2,666,687	180,939
421.1	UNDISTR EARNINGS OF SUBS	1,822,726	28,573,380	28,617,887	(44,507)
	TOTAL OTHER INCOME	2,756,239	41,614,087	42,074,862	(460,776)

HAWAIIAN ELECTRIC COMPANY, INC
MONTHLY FINANCIAL REPORT
DECEMBER 1998

TO THE PUBLIC UTILITIES COMMISSION OF THE STATE OF HAWAII
COMPARATIVE ANALYSIS OF INCOME AND RETAINED EARNINGS

			ACCUMULATED TOTALS		INC-DEC
		THIS MONTH	CURRENT YTD	PRIOR YTD	ACCUM TOTALS
	OTHER INCOME DEDUCTIONS				
408.2	OTHER TAXES ON OTH INCOME	(361)	18,321	60,757	(42,435)
409.2*	INCOME TAXES ON OTH INCOME	(71,981)	(148,052)	(179,058)	31,005
425/26	MISC INCOME DEDUCTIONS	160,761	541,221	576,396	(35,175)
	TOTAL OTHER INCOME DEDUCTIONS	88,419	411,490	458,095	(46,604)
	INTEREST CHARGES				
427.0	INTEREST ON LONG-TERM DEBT	1,883,862	24,013,131	24,268,393	(255,262)
428.0	AMORT OF DEBT DISC & EXPENSE	77,359	958,028	871,165	86,862
429.0	AMORT OF PREMIUM ON DEBT-CR	0	0	0	0
430.0	INTER ON DEBT TO ASSOC COS	344,263	2,855,998	2,411,675	444,323
431.0	OTHER INTEREST EXPENSE	372,168	6,198,118	6,907,594	(709,476)
	TOTAL INTEREST CHARGES	2,677,651	34,025,275	34,458,827	(433,552)
	INCOME BEFORE EXTRAORD ITEMS	4,593,479	84,229,131	81,848,693	2,380,437
	EXTRAORDINARY ITEMS (NET)	0	0	0	0
	NET INCOME	4,593,479	84,229,131	81,848,693	2,380,437
	RETAINED EARNINGS (BEG OF PER)	420,261,176	387,582,092	367,769,778	19,812,315
435.0	BALANCE TRANSFERRED FROM INC	4,593,479	84,229,131	81,848,693	2,380,437
439.0	ADJ TO RETAIN EARN	0	0	0	0
437.0	DIVIDENDS DECLAR-PREF STOCK	287,090	3,453,659	3,659,379	(205,720)
438.0	DIVIDENDS DECLAR-COM STOCK	18,732,000	62,522,000	58,377,000	4,145,000
	RETAINED EARNINGS (END OF PER)	405,835,564	405,835,564	387,582,092	18,253,472

* ALSO INCLUDES ACCOUNTS 410.2 AND 411.2.

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HAWAIIAN ELECTRIC COMPANY, INC.
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TO THE PUBLIC UTILITIES COMMISSION OF THE STATE OF HAWAII
ANALYSIS OF OPERATING EXPENSES

		TOTALS FOR		ACCUMULATED TOTALS		INCREASE-DECREASE ACCUM.TOTALS
		THIS MONTH	SAME MONTH LAST YEAR	THIS YEAR	SAME PERIOD LAST YEAR	
	PRODUCTION EXPENSES:					
	Steam Power Generation					
500/07	Operation	11,902,369	14,636,697	142,266,596	185,830,059	(43,563,464)
510/14	Maintenance	1,247,911	1,397,942	12,702,014	16,615,348	(3,913,334)
	Other Pwr/Fuel Generation					
546/50	Operation	26,416	21,031	237,283	354,367	(117,084)
551/54	Maintenance	45,978	7,006	252,538	57,661	194,877
555/57	Other Purch. Pwr Expenses	21,118,343	21,516,184	238,689,468	252,863,558	(14,174,089)
	TRANSMISSION EXPENSES:					
560/67	Operation	415,750	366,749	4,227,698	3,630,983	596,715
568/72	Maintenance	777,256	346,524	3,562,212	3,560,348	1,865
	DISTRIBUTION EXPENSES:					
580/89	Operation	583,889	739,026	7,131,633	7,707,788	(576,155)
590/98	Maintenance	1,070,712	1,066,542	8,738,253	9,734,464	(996,211)
901/05	CUSTOMER A/C EXPENSES:	752,499	907,628	9,406,356	9,626,795	(220,439)
909/12	CUST. SERVICE EXPENSES:	1,404,596	1,114,430	10,496,869	9,272,011	1,224,858
	ADMINISTRATIVE & GENERAL:					
920/31	Operation	4,731,879	3,823,327	45,682,104	51,058,514	(5,376,410)
932.0	Maintenance	108,215	157,675	1,052,869	1,049,779	3,090
	TOTAL OPERATING EXPENSES	44,185,812	46,100,760	484,445,893	551,361,673	(66,915,780)
401	Total Operation Expenses	40,935,740	43,125,072	458,138,007	520,344,074	(62,206,067)
402	Total Maint. Expenses	3,250,072	2,975,688	26,307,887	31,017,600	(4,709,713)

HAWAIIAN ELECTRIC COMPANY, INC.
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TO THE PUBLIC UTILITIES COMMISSION OF THE STATE OF HAWAII
COMPARATIVE ANALYSIS OF INCOME AND RETAINED EARNINGS

		ACCUMULATED TOTALS		INC(DEC)
	THIS MONTH	CURRENT YTD	PRIOR YTD	ACCUM TOTALS
UTILITY OPERATING INCOME:				
OPERATING REVENUES (Page 3)	69,428,907	732,410,111	716,841,313	15,568,798
OPERATING EXPENSES:				
Operating & Maint Exps (Page 4)	50,285,681	499,783,634	484,445,893	15,337,741
Depreciation Expense	5,265,583	61,869,302	58,008,745	3,860,557
Amort of Utility Plant	53,330	639,961	592,665	47,296
Amort of Contrib in Aid of Constr	(514,250)	(6,171,011)	(5,787,694)	(383,317)
Taxes Other than Income Taxes	6,977,615	69,726,897	67,426,683	2,300,214
Income Taxes	1,651,018	26,270,489	31,569,606	(5,299,117)
Prov for Deferred Income Tax	1,329,629	1,921,664	(1,031,991)	2,953,655
Prov for Deferred ITC	(1,058,980)	1,174,497	1,815,930	(641,433)
Income Tax Def in Prior Yrs	7,571	2,159,508	3,398,398	(1,238,890)
Amort of Def ITC	(55,451)	(665,456)	(648,731)	(16,725)
TOTAL OPERATING EXPENSES	63,941,746	656,709,485	639,789,504	16,919,981
TOTAL OPERATING INCOME	5,487,160	75,700,626	77,051,809	(1,351,183)
OTHER INCOME:				
Income from Non-util Operations	14,797	3,204	90,216	(87,012)
Interest & Dividend Income	(2,737)	2,239,937	2,898,076	(658,139)
Allow for Fund Used-Constr	322,160	5,215,954	7,204,789	(1,988,835)
Misc Non-Operating Income	147,625	2,151,838	2,847,626	(695,788)
Undistributed Earnings of Subs	1,978,338	27,336,509	28,573,380	(1,236,871)
TOTAL OTHER INCOME	2,460,183	36,947,442	41,614,087	(4,666,645)
OTHER INCOME DEDUCTIONS:				
Other Taxes on Oth Income	6,336	7,822	18,321	(10,499)
Income Taxes on Oth Income	(59,423)	(179,750)	(148,052)	(31,698)
Misc Income Deductions	198,733	864,262	541,221	323,041
TOTAL OTHER INC DEDUCTIONS	145,646	692,334	411,490	280,844
INTEREST CHARGES:				
Interest on Long-Term Debt	1,973,020	22,636,466	24,013,131	(1,376,665)
Amort of Debt Discount & Expense	98,841	1,067,963	958,028	109,935
Interest on Debt to Assoc Co.	437,710	5,312,382	2,855,998	2,456,384
Other Interest Expense	363,866	6,537,837	6,198,118	339,719
TOTAL INTEREST CHARGES	2,873,438	35,554,648	34,025,275	1,529,373
INCOME BEFORE EXTRAORD ITEMS	4,928,259	76,401,086	84,229,131	(7,828,045)
EXTRAORDINARY ITEMS(NET)	0	0	0	0
NET INCOME	4,928,259	76,401,086	84,229,131	(7,828,045)
RETAINED EARNINGS (Beg of Per)	435,603,927	405,835,564	387,582,092	18,253,472
Balance Trsf from Income	4,928,259	76,401,086	84,229,131	(7,828,045)
Dividends Declared-Preferred	89,992	1,178,456	3,453,659	(2,275,203)
Dividends Declared-Common	15,236,000	55,852,000	62,522,000	(6,670,000)
RETAINED EARNINGS (End of Per)	425,206,194	425,206,194	405,835,564	19,370,630

HAWAIIAN ELECTRIC COMPANY, INC.
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TO THE PUBLIC UTILITIES COMMISSION OF THE STATE OF HAWAII
ANALYSIS OF OPERATING EXPENSES

	TOTALS FOR		ACCUMULATED TOTALS		INCREASE
	THIS MONTH	SAME MONTH LAST YEAR	THIS YEAR	SAME PERIOD LAST YEAR	(DECREASE) ACCUM TOTALS
PRODUCTION EXPENSES:					
Steam Power Generation					
Operation	16,127,377	11,902,369	152,302,657	142,266,596	10,036,061
Maintenance	3,191,042	1,247,911	17,610,729	12,702,014	4,908,715
Other Power/Fuel Generation					
Operation	81,295	26,416	703,249	237,283	465,966
Maintenance	8,716	45,978	187,150	252,538	(65,388)
Other Purch. Power Expenses	22,640,635	21,118,343	240,832,443	238,689,468	2,142,975
TRANSMISSION EXPENSES:					
Operation	425,794	415,750	3,135,885	4,227,698	(1,091,813)
Maintenance	547,320	777,256	3,489,827	3,562,212	(72,385)
DISTRIBUTION EXPENSES:					
Operation	849,432	583,889	8,157,289	7,131,633	1,025,656
Maintenance	1,281,740	1,070,712	10,593,314	8,738,253	1,855,061
CUSTOMER A/C EXPENSES:	930,831	752,499	9,345,797	9,406,356	(60,559)
CUSTOMER SERVICE EXPENSES:	1,095,499	1,404,596	9,378,760	10,496,869	(1,118,109)
ADMINISTRATIVE & GENERAL:					
Operation	3,056,279	4,731,879	43,338,165	45,682,104	(2,343,939)
Maintenance	49,721	108,215	708,369	1,052,869	(344,500)
TOTAL OPERATING EXPENSES	50,285,681	44,185,814	499,783,634	484,445,893	15,337,741
Total Operation Expenses	45,207,142	40,935,741	467,194,245	458,138,007	9,056,238
Total Maintenance Expenses	5,078,539	3,250,072	32,589,389	26,307,887	6,281,502

HAWAIIAN ELECTRIC COMPANY, INC.
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TO THE PUBLIC UTILITIES COMMISSION OF THE STATE OF HAWAII
COMPARATIVE ANALYSIS OF INCOME AND RETAINED EARNINGS

	THIS MONTH	ACCUMULATED TOTALS CURRENT YTD	ACCUMULATED TOTALS PRIOR YTD	INC(DEC) ACCUM TOTALS
UTILITY OPERATING INCOME:				
OPERATING REVENUES (Page 3)	79,549,642	883,414,532	732,410,110	151,004,422
OPERATING EXPENSES:				
Operating & Maint Exps (Page 4)	64,240,179	625,309,931	499,783,635	125,526,296
Depreciation Expense	6,098,725	65,198,961	61,869,300	3,329,661
Amort of Utility Plant	55,306	663,667	639,963	23,704
Amort of Contrib in Aid of Constr	(521,203)	(6,254,439)	(6,171,011)	(83,428)
Taxes Other than Income Taxes	7,353,576	83,168,988	69,726,896	13,442,093
Income Taxes	2,453,357	28,377,740	26,270,489	2,107,251
Prov for Deferred Income Tax	87,099	7,539,032	1,921,663	5,617,368
Prov for Deferred ITC	(84,569)	1,700,518	1,174,497	526,021
Income Tax Def in Prior Yrs	(2,657,789)	(2,657,789)	2,159,508	(4,817,297)
Amort of Def ITC	(58,634)	(703,604)	(665,456)	(38,148)
TOTAL OPERATING EXPENSES	76,966,046	802,343,005	656,709,484	145,633,521
TOTAL OPERATING INCOME	2,583,596	81,071,527	75,700,626	5,370,901
OTHER INCOME:				
Income from Non-util Operations	129,053	1,130,669	3,204	1,127,465
Interest & Dividend Income	452,671	2,615,725	2,239,936	375,789
Allow for Fund Used-Constr	508,656	6,588,462	5,215,951	1,372,511
Misc Non-Operating Income	493,874	3,012,620	2,151,838	860,782
Undistributed Earnings of Subs	1,509,679	32,985,715	27,336,509	5,649,206
TOTAL OTHER INCOME	3,093,933	46,333,192	36,947,439	9,385,753
OTHER INCOME DEDUCTIONS:				
Other Taxes on Oth Income	(16,775)	186,456	7,820	178,636
Income Taxes on Oth Income	155,450	303,079	(179,750)	482,830
Misc Income Deductions	747,310	1,459,851	864,263	595,588
TOTAL OTHER INC DEDUCTIONS	885,985	1,949,386	692,333	1,257,054
INTEREST CHARGES:				
Interest on Long-Term Debt	2,045,845	23,368,618	22,636,466	732,152
Amort of Debt Discount & Expense	107,016	1,262,335	1,067,963	194,373
Interest on Debt to Assoc Co.	438,870	5,546,470	5,312,382	234,088
Other Interest Expense	649,966	6,912,250	6,537,837	374,413
TOTAL INTEREST CHARGES	3,241,696	37,089,673	35,554,647	1,535,026
INCOME BEFORE EXTRAORD ITEMS	1,549,848	88,365,659	76,401,085	11,964,574
EXTRAORDINARY ITEMS(NET)	0	0	0	0
NET INCOME	1,549,848	88,365,659	76,401,085	11,964,574
RETAINED EARNINGS (Beg of Per)	461,275,091	425,206,194	405,835,564	19,370,629
Balance Trsf from Income	1,549,848	88,365,659	76,401,085	11,964,574
Dividends Declared-Preferred	89,992	1,079,907	1,178,456	(98,548)
Dividends Declared-Common	18,765,000	68,522,000	55,852,000	12,670,000
RETAINED EARNINGS (End of Per)	443,969,946	443,969,946	425,206,194	18,763,752

HAWAIIAN ELECTRIC COMPANY, INC.
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TO THE PUBLIC UTILITIES COMMISSION OF THE STATE OF HAWAII
ANALYSIS OF OPERATING EXPENSES

	TOTALS FOR		ACCUMULATED TOTALS		INCREASE
	THIS MONTH	SAME MONTH LAST YEAR	THIS YEAR	SAME PERIOD LAST YEAR	(DECREASE) ACCUM TOTALS
PRODUCTION EXPENSES:					
Steam Power Generation					
Operation	23,709,949	16,127,377	256,043,834	152,302,658	103,741,177
Maintenance	4,415,662	3,191,042	24,178,438	17,610,729	6,567,709
Other Power/Fuel Generation					
Operation	74,948	81,295	776,041	703,249	72,792
Maintenance	86,928	8,716	198,813	187,150	11,664
Other Purch. Power Expenses	23,888,188	22,640,635	263,432,226	240,832,443	22,599,783
TRANSMISSION EXPENSES:					
Operation	292,644	425,794	3,022,883	3,135,885	(113,002)
Maintenance	849,757	547,320	4,031,281	3,489,827	541,454
DISTRIBUTION EXPENSES:					
Operation	686,404	849,432	8,100,024	8,157,289	(57,265)
Maintenance	2,077,932	1,281,741	14,121,263	10,593,314	3,527,949
CUSTOMER A/C EXPENSES:	2,005,864	930,831	11,171,064	9,345,797	1,825,267
CUSTOMER SERVICE EXPENSES:	1,088,307	1,095,499	9,874,491	9,378,761	495,730
ADMINISTRATIVE & GENERAL:					
Operation	4,949,507	3,056,279	29,385,006	43,338,166	(13,953,160)
Maintenance	114,090	49,721	974,566	708,369	266,197
TOTAL OPERATING EXPENSES	64,240,179	50,285,682	626,309,931	499,783,635	125,526,296
Total Operation Expenses	56,695,811	45,207,142	581,805,569	467,194,246	114,611,323
Total Maintenance Expenses	7,544,368	5,078,539	43,504,362	32,589,389	10,914,973

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HAWAIIAN ELECTRIC COMPANY, INC.
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TO THE PUBLIC UTILITIES COMMISSION OF THE STATE OF HAWAII
COMPARATIVE ANALYSIS OF INCOME AND RETAINED EARNINGS

	THIS MONTH	ACCUMULATED TOTALS CURRENT YTD	PRIOR YTD	INC / DEC (-) ACCUM TOTALS
UTILITY OPERATING INCOME				
Operating Revenues	69,191,876	885,243,776	883,414,532	1,829,244
OPERATING EXPENSES				
Operating & Maintenance Exp	53,015,679	620,979,352	625,309,931	-4,330,579
Depreciation	5,612,522	67,191,864	65,198,961	1,992,902
Amort of Utility Plant 404	47,305	567,659	663,667	-96,008
Amort of CIAC	-580,018	-6,960,238	-6,254,439	-705,799
Taxes Other than Income	6,263,220	83,310,217	83,168,988	141,229
Income Taxes	-1,714,692	27,879,565	28,377,740	-498,175
Prov for Deferred Tax	401,735	5,389,608	7,539,032	-2,149,423
Prov for Deferred ITC	1,021,869	2,188,809	1,700,518	488,291
Income Tax Prior Year	1,076,877	1,076,877	-2,657,789	3,734,666
Amort of Def ITC	-63,357	-760,289	-703,604	-56,685
TOTAL OPERATING EXPENSES	65,081,140	800,863,424	802,343,005	-1,479,581
OPERATING INCOME	4,110,736	84,380,352	81,071,527	3,308,825
OTHER INCOME				
Inc from Non-Util Operations	139,859	1,443,353	1,130,669	312,684
Non-Operating Rental Income	0	0	0	0
Interest and Dividends	139,069	1,372,860	2,615,725	-1,242,865
AFUDC	430,421	5,389,006	6,588,462	-1,199,457
Misc Non-Operating Income	178,080	2,232,469	3,012,620	-780,151
Undistr Earnings of Subs	1,470,377	31,096,947	32,985,715	-1,888,768
TOTAL OTHER INCOME	2,357,805	41,534,635	46,333,192	-4,798,557
OTHER INCOME DEDUCTIONS				
Other Taxes on Oth Income	7,088	22,886	186,456	-163,571
Income Taxes on Oth Income	-129,135	-15,678	303,079	-318,758
Misc Income Deductions	475,869	1,594,364	1,459,851	134,513
TOTAL OTHER INC DEDUCT	353,822	1,601,571	1,949,386	-347,816
INTEREST CHARGES				
Interest on Long-Term Debt	2,027,934	23,849,148	23,368,618	480,530
Amort of Debt Discount & Exp	106,373	1,309,543	1,262,335	47,207
Amort of Premium on Debt - CR	0	0	0	0
Int on Debt to Assoc Co.	465,446	6,196,058	5,546,470	649,588
Other Interest Exp	122,937	3,578,788	6,912,250	-3,333,462
TOTAL INTEREST CHARGES	2,722,690	34,933,538	37,089,673	-2,156,136
INC BEF EXTRAORD ITEMS	3,392,029	89,379,879	88,365,659	1,014,219
EXTRAORDINARY ITEMS	0	0	0	0
NET INCOME	3,392,029	89,379,879	88,365,659	1,014,219
RETAINED EARNINGS (Beg)	511,930,881	443,969,946	425,206,194	18,763,752
Balance Trsf from Income	3,392,029	89,379,879	88,365,659	1,014,219
Adj to Retained Earnings	0	0	0	0
Dividends - Preferred	89,992	1,079,907	1,079,907	0
Dividends - Common	19,272,000	36,309,000	68,522,000	-32,213,000
RETAINED EARNINGS (End)	495,960,918	495,960,918	443,969,946	51,990,972

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TO THE PUBLIC UTILITIES COMMISSION OF THE STATE OF HAWAII
ANALYSIS OF OPERATING EXPENSES

	TOTALS FOR THIS MONTH	SAME MONTH LAST YEAR	THIS YEAR	SAME PERIOD LAST YEAR	INCREASE / DECREASE ACCUM TOTALS
PRODUCTION EXPENSES:					
Steam Power Generation					
Operation	19,645,439	23,709,949	255,866,315	256,043,834	-177,519
Maintenance	3,648,409	4,415,662	22,012,443	24,178,438	-2,165,996
Hydro Power Generation					
Operation	0	0	0	0	0
Maintenance	0	0	0	0	0
Other Power/Fuel Generation					
Operation	153,386	74,948	925,265	776,041	149,224
Maintenance	7,154	86,928	508,647	198,813	309,834
Other Purchase Power Expenses	20,804,047	23,888,188	264,255,058	263,432,226	822,833
TRANSMISSION EXPENSES:					
Operation	400,628	292,644	3,420,695	3,022,883	397,812
Maintenance	300,472	849,757	3,464,397	4,031,281	-566,885
DISTRIBUTION EXPENSES:					
Operation	739,044	686,404	8,049,096	8,100,024	-50,928
Maintenance	1,175,579	2,077,932	12,434,826	14,121,263	-1,686,438
CUSTOMER ACCTS EXPENSES	1,176,482	2,005,864	10,113,346	11,171,064	-1,057,718
CUSTOMER SERVICE EXPENSES	704,301	1,088,307	8,557,315	9,874,491	-1,317,176
ADMINISTRATIVE & GENERAL:					
Operation	4,159,440	4,949,507	30,534,048	29,385,005	1,149,043
Maintenance	101,298	114,090	837,902	974,566	-136,664
TOTAL OPERATING EXPENSES	53,015,679	64,240,179	620,979,352	625,309,931	-4,330,579
Total Operation Expenses	47,782,768	56,695,811	581,721,138	581,805,569	-84,431
Total Maintenance Expenses	5,232,911	7,544,368	39,258,214	43,504,362	-4,246,148

HAWAIIAN ELECTRIC COMPANY, INC.
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TO THE PUBLIC UTILITIES COMMISSION OF THE STATE OF HAWAII
COMPARATIVE ANALYSIS OF INCOME AND RETAINED EARNINGS

	THIS MONTH	ACCUMULATED TOTALS CURRENT YTD	ACCUMULATED TOTALS PRIOR YTD	INC(DEC) ACCUM TOTALS
UTILITY OPERATING INCOME:				
OPERATING REVENUES (Page 3)	77,267,885	868,383,309	885,243,776	(16,860,467)
OPERATING EXPENSES:				
Operating & Maint Exps (Page 4)	57,364,044	599,668,389	620,979,352	(21,310,963)
Depreciation Expense	5,832,114	69,977,849	67,191,864	2,785,985
Amort of Utility Plant	50,782	609,384	567,659	41,725
Amort of Contrib in Aid of Constr	(581,176)	(6,974,106)	(6,960,238)	(13,868)
Taxes Other than Income Taxes	7,343,735	83,089,323	83,310,217	(220,893)
Income Taxes	205,571	27,308,609	27,879,565	(570,956)
Prov for Deferred Income Tax	477,288	7,972,994	5,389,608	2,583,386
Prov for Deferred ITC	136,816	1,782,509	2,188,809	(406,300)
Income Tax Def in Prior Yrs	1,144,683	1,144,683	1,076,877	67,806
Amort of Def ITC	(69,090)	(829,075)	(760,289)	(68,786)
TOTAL OPERATING EXPENSES	71,904,768	783,750,559	800,863,424	(17,112,865)
TOTAL OPERATING INCOME	5,363,117	84,632,750	84,380,352	252,398
OTHER INCOME:				
Income from Non-util Operations	(37,519)	662,648	1,443,353	(780,705)
Interest & Dividend Income	234,068	1,228,178	1,372,860	(144,682)
Allow for Fund Used-Constr	414,107	5,156,850	5,389,006	(232,156)
Misc Non-Operating Income	177,696	2,234,174	2,232,469	1,704
Undistributed Earnings of Subs	(610,252)	30,782,079	31,096,947	(314,868)
TOTAL OTHER INCOME	178,099	40,063,928	41,534,635	(1,470,707)
OTHER INCOME DEDUCTIONS:				
Other Taxes on Oth Income	(258)	30,472	22,886	7,587
Income Taxes on Oth Income	(68,924)	(57,859)	(15,678)	(42,180)
Misc Income Deductions	219,766	981,104	1,594,364	(613,260)
TOTAL OTHER INC DEDUCTIONS	150,584	953,717	1,601,571	(647,853)
INTEREST CHARGES:				
Interest on Long-Term Debt	2,108,145	24,632,050	23,849,148	782,901
Amort of Debt Discount & Expense	108,135	1,290,533	1,309,543	(19,010)
Interest on Debt to Assoc Co.	427,080	5,459,839	6,196,058	(736,219)
Other Interest Expense	(59,518)	1,075,685	3,578,788	(2,503,104)
TOTAL INTEREST CHARGES	2,583,842	32,458,107	34,933,538	(2,475,431)
INCOME BEFORE EXTRAORD ITEMS	2,806,790	91,284,854	89,379,879	1,904,976
EXTRAORDINARY ITEMS(NET)	0	0	0	0
NET INCOME	2,806,790	91,284,854	89,379,879	1,904,976
RETAINED EARNINGS (Beg of Per)	552,111,067	495,960,918	443,969,946	51,990,972
Balance Trsf from Income	2,806,790	91,284,854	89,379,879	1,904,976
Dividends Declared-Preferred	89,992	1,079,907	1,079,907	0
Dividends Declared-Common	12,805,000	44,143,000	36,309,000	7,834,000
RETAINED EARNINGS (End of Per)	542,022,865	542,022,865	495,960,918	46,061,947

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TO THE PUBLIC UTILITIES COMMISSION OF THE STATE OF HAWAII
ANALYSIS OF OPERATING EXPENSES

	TOTALS FOR		ACCUMULATED TOTALS		INCREASE (DECREASE)
	THIS MONTH	SAME MONTH LAST YEAR	THIS YEAR	SAME PERIOD LAST YEAR	ACCUM TOTALS
PRODUCTION EXPENSES:					
Steam Power Generation					
Operation	21,883,916	19,645,439	231,435,785	255,866,315	(24,430,530)
Maintenance	3,269,435	3,648,409	24,815,371	22,012,443	2,802,929
Other Power/Fuel Generation					
Operation	177,651	153,386	1,264,980	925,265	339,715
Maintenance	10,932	7,154	64,774	508,647	(443,873)
Other Purch. Power Expenses	23,696,157	20,804,047	261,780,810	264,255,058	(2,474,248)
TRANSMISSION EXPENSES:					
Operation	288,117	400,628	2,808,804	3,420,695	(611,891)
Maintenance	573,950	300,472	3,889,717	3,464,397	425,320
DISTRIBUTION EXPENSES:					
Operation	534,604	739,044	7,668,997	8,049,096	(380,099)
Maintenance	1,206,978	1,175,579	11,956,955	12,434,826	(477,870)
CUSTOMER A/C EXPENSES:	1,341,683	1,176,482	9,890,609	10,113,346	(222,737)
CUSTOMER SERVICE EXPENSES:	1,197,044	704,301	9,885,995	8,557,315	1,328,680
ADMINISTRATIVE & GENERAL:					
Operation	3,131,229	4,159,440	33,521,494	30,534,048	2,987,446
Maintenance	50,348	101,298	684,096	837,902	(153,805)
TOTAL OPERATING EXPENSES	57,364,044	53,015,679	599,668,369	620,979,352	(21,310,963)
Total Operation Expenses	52,252,401	47,782,768	558,257,474	581,721,138	(23,463,664)
Total Maintenance Expenses	5,111,642	5,232,911	41,410,915	39,258,214	2,152,701

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TO THE PUBLIC UTILITIES COMMISSION OF THE STATE OF HAWAII
COMPARATIVE ANALYSIS OF INCOME AND RETAINED EARNINGS

		ACCUMULATED TOTALS		INC(DEC)
	THIS MONTH	CURRENT YTD	PRIOR YTD	ACCUM TOTALS
UTILITY OPERATING INCOME:				
OPERATING REVENUES (Page 3)	78,651,724	963,500,496	868,383,309	95,117,186
OPERATING EXPENSES:				
Operating & Maint Exps (Page 4)	58,248,167	699,400,386	599,668,389	99,731,997
Depreciation Expense	6,108,815	73,297,319	69,977,849	3,319,470
Amort of Utility Plant	62,340	746,062	609,384	136,696
Amort of Contrib in Aid of Constr	(577,036)	(6,924,454)	(6,974,106)	49,652
Taxes Other than Income Taxes	7,534,039	90,150,368	83,069,323	7,061,045
Income Taxes	(2,925,292)	24,984,782	27,306,609	(2,323,827)
Prov for Deferred Income Tax	5,188,248	6,660,596	7,972,994	(1,312,398)
Prov for Deferred ITC	(760,212)	1,172,138	1,782,509	(610,371)
Income Tax Def in Prior Yrs	393,166	(824,189)	1,144,683	(1,968,872)
Amort of Def ITC	(62,582)	(879,931)	(829,075)	(50,856)
TOTAL OPERATING EXPENSES	73,209,453	887,785,097	783,750,559	104,034,538
TOTAL OPERATING INCOME	5,442,272	75,715,399	84,632,750	(8,917,351)
OTHER INCOME:				
Income from Non-util Operations	(24,222)	146,108	662,648	(516,540)
Interest & Dividend Income	39,740	757,978	1,228,178	(470,200)
Allow for Fund Used-Constr	501,276	5,310,850	5,156,850	154,001
Misc Non-Operating Income	220,840	2,462,197	2,234,174	228,023
Undistributed Earnings of Subs	2,859,709	29,459,309	30,782,079	(1,322,770)
TOTAL OTHER INCOME	3,597,343	38,136,441	40,063,928	(1,927,487)
OTHER INCOME DEDUCTIONS:				
Other Taxes on Oth Income	1,052	12,912	30,472	(17,560)
Income Taxes on Oth Income	(173,496)	(337,240)	(57,859)	(279,381)
Misc Income Deductions	297,166	1,023,857	981,104	42,753
TOTAL OTHER INC DEDUCTIONS	124,722	699,530	953,717	(254,188)
INTEREST CHARGES:				
Interest on Long-Term Debt	2,074,132	25,284,301	24,632,050	652,251
Amort of Debt Discount & Expense	114,320	1,371,212	1,290,533	80,679
Interest on Debt to Assoc Co.	426,962	5,145,025	5,459,839	(314,814)
Other Interest Expense	55,454	1,360,725	1,075,685	285,040
TOTAL INTEREST CHARGES	2,670,869	33,161,263	32,458,107	703,156
INCOME BEFORE EXTRAORD ITEMS	6,244,024	79,991,046	91,284,854	(11,293,806)
EXTRAORDINARY ITEMS(NET)	0	0	0	0
NET INCOME	6,244,024	79,991,048	91,284,854	(11,293,806)
RETAINED EARNINGS (Beg of Per)	572,330,974	542,022,865	495,960,918	46,061,947
Balance Trsf from Income	6,244,024	79,991,048	91,284,854	(11,293,806)
Dividends Declared-Preferred	89,992	1,079,907	1,079,907	0
Dividends Declared-Common	15,270,000	57,719,000	44,143,000	13,576,000
RETAINED EARNINGS (End of Per)	563,215,006	563,215,006	542,022,865	21,192,141

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ANALYSIS OF OPERATING EXPENSES

	TOTALS FOR		ACCUMULATED TOTALS		INCREASE (DECREASE)
	THIS MONTH	SAME MONTH LAST YEAR	THIS YEAR	SAME PERIOD LAST YEAR	ACCUM TOTALS
PRODUCTION EXPENSES:					
Steam Power Generation					
Operation	21,638,740	21,863,916	290,632,403	231,435,785	59,196,618
Maintenance	2,718,684	3,269,435	24,793,313	24,815,371	(22,058)
Other Power/Fuel Generation					
Operation	200,247	177,651	2,475,331	1,264,980	1,210,352
Maintenance	3,190	10,932	85,691	64,774	20,917
Other Purch. Power Expenses	25,072,586	23,698,157	285,520,011	261,780,810	23,739,201
TRANSMISSION EXPENSES:					
Operation	280,341	288,117	3,274,708	2,808,804	465,905
Maintenance	284,224	573,950	3,713,857	3,889,717	(175,860)
DISTRIBUTION EXPENSES:					
Operation	989,264	534,604	7,802,423	7,668,997	133,425
Maintenance	813,369	1,206,978	9,416,726	11,956,955	(2,540,229)
CUSTOMER A/C EXPENSES:	798,987	1,341,683	10,055,330	9,890,609	164,721
CUSTOMER SERVICE EXPENSES:	813,696	1,197,044	9,472,322	9,885,995	(413,673)
ADMINISTRATIVE & GENERAL:					
Operation	4,628,112	3,131,229	51,662,540	33,521,494	18,141,046
Maintenance	28,727	50,348	495,730	684,098	(188,367)
TOTAL OPERATING EXPENSES	58,248,167	57,364,044	699,400,386	599,668,389	99,731,997
Total Operation Expenses	54,401,973	52,252,401	660,895,069	558,257,474	102,637,595
Total Maintenance Expenses	3,846,194	5,111,642	38,505,317	41,410,915	(2,905,598)

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TO THE PUBLIC UTILITIES COMMISSION OF THE STATE OF HAWAII
COMPARATIVE ANALYSIS OF INCOME AND RETAINED EARNINGS

	THIS MONTH	ACCUMULATED TOTALS CURRENT YTD	PRIOR YTD	INC / DEC (-) ACCUM TOTALS
UTILITY OPERATING INCOME				
Operating Revenues	96,597,121	1,053,099,852	963,500,496	89,599,356
OPERATING EXPENSES				
Operating & Maintenance Exp	80,140,043	785,228,643	699,400,386	85,828,257
Depreciation	6,768,738	76,102,159	73,297,319	2,804,840
Amort of Utility Plant	51,354	651,190	748,082	-96,892
Amort of CIAC	-607,223	-7,286,654	-6,924,454	-362,200
Taxes Other than Income	9,069,676	97,973,967	90,150,368	7,823,599
Income Taxes	-510,898	16,833,922	24,984,782	-8,150,860
Prov for Deferred Tax	-68,427	8,173,708	6,660,596	1,513,112
Prov for Deferred ITC	266,292	3,311,687	1,172,138	2,139,549
Income Tax Prior Year	-915,693	2,161,455	-824,189	2,985,644
Amort of Def ITC	-82,714	-996,453	-879,931	-116,522
TOTAL OPERATING EXPENSES	94,111,149	982,153,625	887,785,097	94,368,528
OPERATING INCOME	2,485,971	70,946,226	75,715,399	-4,769,173
OTHER INCOME				
Inc from Non-Util Operations	-108	-8,618	146,108	-154,726
Non-Operating Rental Income	690	4,770	0	4,770
Interest and Dividends	106,769	729,405	757,978	-28,573
AFUDC	-759,467	7,538,166	5,310,850	2,227,316
Misc Non-Operating Income	-329,617	3,438,870	2,462,197	976,673
Undistr Earnings of Subs	-587,663	31,930,506	29,459,309	2,471,197
TOTAL OTHER INCOME	-1,569,396	43,633,099	38,136,441	5,496,658
OTHER INCOME DEDUCTIONS				
Other Taxes on Oth Income	-1,057	5,709	12,912	-7,203
Income Taxes on Oth Income	-131,084	-373,841	-337,240	-36,602
Misc Income Deductions	340,165	1,065,366	1,023,857	41,508
TOTAL OTHER INC DEDUCT	208,024	697,233	699,530	-2,297
INTEREST CHARGES				
Interest on Long-Term Debt	2,084,874	24,954,004	25,284,301	-330,298
Amort of Debt Discount & Exp	110,827	1,464,230	1,371,212	93,019
Amort of Premium on Debt - CR	0	0	0	0
Int on Debt to Assoc Co.	253,977	3,865,560	5,145,025	-1,279,465
Other Interest Exp	158,670	1,341,514	1,360,725	-19,210
TOTAL INTEREST CHARGES	2,608,347	31,625,308	33,161,263	-1,535,954
INC BEF EXTRAORD ITEMS	-1,899,796	82,256,784	79,991,048	2,265,737
EXTRAORDINARY ITEMS	0	0	0	0
NET INCOME	-1,899,796	82,256,784	79,991,048	2,265,737
RETAINED EARNINGS (Beg)	634,768,672	563,215,006	542,022,865	21,192,141
Balance Trsf from Income	-1,899,796	82,256,784	79,991,048	2,265,737
Adj to Retained Earnings	0	0	0	0
Dividends - Preferred	89,992	1,079,907	1,079,907	0
Dividends - Common	0	11,613,000	57,719,000	-46,106,000
RETAINED EARNINGS (End)	632,778,884	632,778,884	563,215,006	69,563,877

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ANALYSIS OF OPERATING EXPENSES

	TOTALS FOR THIS MONTH	SAME MONTH LAST YEAR	THIS YEAR	SAME PERIOD LAST YEAR	INCREASE / DECREASE ACCUM TOTALS
PRODUCTION EXPENSES:					
Steam Power Generation					
Operation	35,875,448	21,638,740	347,252,794	290,632,403	56,620,390
Maintenance	4,188,540	2,718,684	29,018,755	24,793,313	4,225,441
Hydro Power Generation					
Operation	0	0	0	0	0
Maintenance	0	0	0	0	0
Other Power/Fuel Generation					
Operation	169,297	200,247	7,321,353	2,475,331	4,846,022
Maintenance	624,249	3,190	1,151,694	85,691	1,066,003
Other Purchase Power Expenses	25,959,233	25,072,586	296,956,014	285,520,011	11,436,003
TRANSMISSION EXPENSES:					
Operation	398,841	280,341	3,532,486	3,274,708	257,777
Maintenance	752,417	284,224	4,574,169	3,713,857	860,312
DISTRIBUTION EXPENSES:					
Operation	1,389,000	969,264	8,404,463	7,802,423	602,041
Maintenance	1,436,978	813,369	12,597,112	9,416,726	3,180,386
CUSTOMER ACCTS EXPENSES	1,884,470	798,987	10,732,176	10,055,330	676,846
CUSTOMER SERVICE EXPENSES	1,344,949	813,696	10,935,468	9,472,322	1,463,146
ADMINISTRATIVE & GENERAL:					
Operation	5,974,603	4,628,112	52,247,281	51,662,540	584,741
Maintenance	142,018	26,727	504,878	495,730	9,147
TOTAL OPERATING EXPENSES	80,140,043	58,248,167	785,228,643	699,400,386	85,828,257
Total Operation Expenses	72,995,840	54,401,973	737,382,036	660,895,069	76,486,967
Total Maintenance Expenses	7,144,203	3,846,194	47,846,608	38,505,317	9,341,291

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TO THE PUBLIC UTILITIES COMMISSION OF THE STATE OF HAWAII
COMPARATIVE ANALYSIS OF INCOME AND RETAINED EARNINGS

	THIS MONTH	ACCUMULATED TOTALS CURRENT YTD	PRIOR YTD	INC / DEC (-) ACCUM TOTALS
UTILITY OPERATING INCOME				
Operating Revenues	112,718,247	1,204,219,418	1,053,099,852	151,119,566
OPERATING EXPENSES				
Operating & Maintenance Exp	91,582,834	930,006,698	785,228,643	144,778,054
Depreciation	6,442,884	78,046,382	76,102,159	1,944,223
Amort of Utility Plant	10,329	123,947	651,190	-527,243
Amort of CIAC	-623,639	-7,483,701	-7,286,654	-197,047
Taxes Other than Income	10,799,354	112,081,626	97,973,967	14,107,659
Income Taxes	692,816	11,003,834	16,833,922	-5,830,088
Prov for Deferred Tax	528,360	-915,635	8,173,708	-9,089,343
Prov for Deferred ITC	63,517	2,839,342	3,311,687	-472,345
Income Tax Prior Year	0	14,333,007	2,161,455	12,171,552
Amort of Def ITC	-91,913	-1,116,972	-996,453	-120,519
TOTAL OPERATING EXPENSES	109,404,542	1,138,918,527	982,153,625	156,764,902
OPERATING INCOME	3,313,706	65,300,890	70,946,226	-5,645,336
OTHER INCOME				
Inc from Non-Util Operations	-2,632	129,095	-8,618	137,713
Non-Operating Rental Income	0	0	4,770	-4,770
Interest and Dividends	202,772	1,971,341	729,405	1,241,936
AFUDC	504,813	5,606,057	7,538,166	-1,932,109
Misc Non-Operating Income	233,190	2,816,514	3,438,870	-622,355
Undistr Earnings of Subs	-160,346	31,052,856	31,930,506	-877,650
TOTAL OTHER INCOME	777,797	41,575,863	43,633,099	-2,057,236
OTHER INCOME DEDUCTIONS				
Other Taxes on Oth Income	567	12,500	5,709	6,791
Income Taxes on Oth Income	-235,488	-453,897	-373,841	-80,056
Misc Income Deductions	596,770	1,205,233	1,065,366	139,867
TOTAL OTHER INC DEDUCT	361,849	763,836	697,233	66,603
INTEREST CHARGES				
Interest on Long-Term Debt	2,076,435	24,836,898	24,954,004	-117,105
Amort of Debt Discount & Exp	112,901	1,379,319	1,464,230	-84,911
Amort of Premium on Debt - CR	0	0	0	0
Int on Debt to Assoc Co.	209,633	2,722,902	3,865,560	-1,142,658
Other Interest Exp	-65,038	3,291,898	1,341,514	1,950,384
TOTAL INTEREST CHARGES	2,333,931	32,231,017	31,625,308	605,709
INC BEF EXTRAORD ITEMS	1,395,722	73,881,901	82,256,784	-8,374,884
EXTRAORDINARY ITEMS	0	0	0	0
NET INCOME	1,395,722	73,881,901	82,256,784	-8,374,884
RETAINED EARNINGS (Beg)	670,320,147	632,778,884	563,215,006	69,563,877
Balance Trsf from Income	1,395,722	73,881,901	82,256,784	-8,374,884
Adj to Retained Earnings	0	0	0	0
Dividends - Preferred	89,992	1,079,907	1,079,907	0
Dividends - Common	16,940,000	50,895,000	11,613,000	39,282,000
RETAINED EARNINGS (End)	654,685,877	654,685,877	632,778,884	21,906,994

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ANALYSIS OF OPERATING EXPENSES

	TOTALS FOR THIS MONTH	SAME MONTH LAST YEAR	THIS YEAR	SAME PERIOD LAST YEAR	INCREASE / DECREASE ACCUM TOTALS
PRODUCTION EXPENSES:					
Steam Power Generation					
Operation	43,363,126	35,875,448	432,563,859	347,252,794	85,311,065
Maintenance	4,271,899	4,188,540	31,002,459	29,018,755	1,983,705
Hydro Power Generation					
Operation	0	0	0	0	0
Maintenance	0	0	0	0	0
Other Power/Fuel Generation					
Operation	960,427	169,297	9,638,170	7,321,353	2,316,817
Maintenance	232,095	624,249	3,668,065	1,151,694	2,516,371
Other Purchase Power Expenses	30,385,357	25,959,233	339,897,010	296,956,014	42,940,996
TRANSMISSION EXPENSES:					
Operation	365,481	398,841	3,970,794	3,532,486	438,308
Maintenance	233,813	752,417	3,860,564	4,574,169	-713,605
DISTRIBUTION EXPENSES:					
Operation	1,380,018	1,389,000	9,549,514	8,404,463	1,145,050
Maintenance	1,279,863	1,436,978	13,492,116	12,597,112	895,004
CUSTOMER ACCTS EXPENSES	1,311,042	1,884,470	11,148,829	10,732,176	416,654
CUSTOMER SERVICE EXPENSES	1,456,862	1,344,949	12,289,069	10,935,468	1,353,601
ADMINISTRATIVE & GENERAL:					
Operation	6,278,202	5,974,603	58,402,077	52,247,281	6,154,795
Maintenance	64,647	142,018	524,172	504,878	19,294
TOTAL OPERATING EXPENSES	91,582,834	80,140,043	930,006,698	785,228,643	144,778,054
Total Operation Expenses	85,500,517	72,995,840	877,459,321	737,382,036	140,077,285
Total Maintenance Expenses	6,082,317	7,144,203	52,547,376	47,846,608	4,700,769

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TO THE PUBLIC UTILITIES COMMISSION OF THE STATE OF HAWAII
COMPARATIVE ANALYSIS OF INCOME AND RETAINED EARNINGS

	THIS MONTH	ACCUMULATED TOTALS CURRENT YTD	ACCUMULATED TOTALS PRIOR YTD	INC / DEC (-) ACCUM TOTALS
UTILITY OPERATING INCOME				
Operating Revenues	105,508,543	1,365,593,403	1,204,219,418	161,373,985
OPERATING EXPENSES				
Operating & Maintenance Exp	82,749,629	1,057,386,203	930,006,698	127,379,505
Depreciation	6,902,032	82,816,517	78,046,382	4,770,135
Amort of Utility Plant	3,097	37,160	123,947	-86,787
Amort of CIAC	-671,314	-8,055,713	-7,483,701	-572,012
Taxes Other than Income	9,955,407	126,848,589	112,081,626	14,766,963
Income Taxes	3,055,321	36,812,519	11,003,834	25,808,685
Prov for Deferred Tax	-1,174,815	-8,588,145	-915,635	-7,672,510
Prov for Deferred ITC	-205,717	3,198,233	2,839,342	358,891
Income Tax Prior Year	166,447	992,658	14,333,007	-13,340,349
Amort of Def ITC	-99,800	-1,200,960	-1,116,972	-83,988
TOTAL OPERATING EXPENSES	100,680,288	1,290,247,060	1,138,918,527	151,328,533
OPERATING INCOME	4,828,255	75,346,343	65,300,890	10,045,452
OTHER INCOME				
Inc from Non-Util Operations	-11,843	-58,914	129,095	-188,009
Non-Operating Rental Income	0	0	0	0
Interest and Dividends	243,580	2,792,854	1,971,341	821,514
AFUDC	511,361	5,874,997	5,606,057	268,940
Misc Non-Operating Income	225,067	2,697,748	2,816,514	-118,766
Undistr Earnings of Subs	-260,819	25,683,432	31,052,856	-5,369,424
TOTAL OTHER INCOME	707,346	36,990,117	41,575,863	-4,585,746
OTHER INCOME DEDUCTIONS				
Other Taxes on Oth Income	217	1,911	12,500	-10,589
Income Taxes on Oth Income	-287,419	-852,780	-453,897	-398,882
Misc Income Deductions	726,798	1,996,421	1,205,233	791,188
TOTAL OTHER INC DEDUCT	439,595	1,145,552	763,836	381,716
INTEREST CHARGES				
Interest on Long-Term Debt	2,076,434	24,916,279	24,836,898	79,380
Amort of Debt Discount & Exp	115,756	1,378,419	1,379,319	-901
Amort of Premium on Debt - CR	0	0	0	0
Int on Debt to Assoc Co.	170,876	2,089,622	2,722,902	-633,280
Other Interest Exp	554,466	6,779,845	3,291,898	3,487,947
TOTAL INTEREST CHARGES	2,917,533	35,164,164	32,231,017	2,933,147
INC BEF EXTRAORD ITEMS	2,178,473	76,026,744	73,881,901	2,144,843
EXTRAORDINARY ITEMS	0	0	0	0
NET INCOME	2,178,473	76,026,744	73,881,901	2,144,843
RETAINED EARNINGS (Beg)	698,163,233	654,685,877	632,778,884	21,906,994
Balance Trsf from Income	2,178,473	76,026,744	73,881,901	2,144,843
Adj to Retained Earnings	0	0	0	0
Dividends - Preferred	89,992	1,079,907	1,079,907	0
Dividends - Common	0	29,381,000	50,895,000	-21,514,000
RETAINED EARNINGS (End)	700,251,714	700,251,714	654,685,877	45,565,837

HAWAIIAN ELECTRIC COMPANY, INC.
MONTHLY FINANCIAL REPORT
December 2006

TO THE PUBLIC UTILITIES COMMISSION OF THE STATE OF HAWAII
ANALYSIS OF OPERATING EXPENSES

	TOTALS FOR THIS MONTH	SAME MONTH LAST YEAR	THIS YEAR	SAME PERIOD LAST YEAR	INCREASE / DECREASE ACCUM TOTALS
PRODUCTION EXPENSES:					
Steam Power Generation					
Operation	36,379,878	43,363,126	531,202,350	432,563,859	98,638,492
Maintenance	3,906,860	4,271,899	33,492,415	31,002,459	2,489,956
Hydro Power Generation					
Operation	0	0	0	0	0
Maintenance	0	0	0	0	0
Other Power/Fuel Generation					
Operation	583,753	960,427	9,534,567	9,638,170	-103,604
Maintenance	92,999	232,095	4,412,108	3,668,065	744,043
Other Purchase Power Expenses	29,835,418	30,385,357	358,880,243	339,897,010	18,983,234
TRANSMISSION EXPENSES:					
Operation	346,872	365,481	4,236,445	3,970,794	265,652
Maintenance	651,992	233,813	5,253,116	3,860,564	1,392,552
DISTRIBUTION EXPENSES:					
Operation	980,718	1,380,018	9,039,730	9,549,514	-509,783
Maintenance	1,585,235	1,279,863	13,130,607	13,492,116	-361,510
CUSTOMER ACCTS EXPENSES	1,721,155	1,311,042	12,316,784	11,148,829	1,167,955
CUSTOMER SERVICE EXPENSES	1,640,554	1,456,862	15,336,120	12,289,069	3,047,051
ADMINISTRATIVE & GENERAL:					
Operation	4,965,345	6,278,202	60,107,463	58,402,077	1,705,386
Maintenance	58,847	64,647	444,253	524,172	-79,919
TOTAL OPERATING EXPENSES	82,749,629	91,582,834	1,057,386,203	930,006,698	127,379,505
Total Operation Expenses	76,453,694	85,500,517	1,000,653,704	877,459,321	123,194,383
Total Maintenance Expenses	6,295,935	6,082,317	56,732,499	52,547,376	4,185,123

DOD-IR-16

Please provide a description of Hawaiian Electric Company's five largest industrial and commercial customers (name of customer can be withheld), and indicate what percentage of the Company's total 2005 and 2006 kWh amount and revenues each represents. Also, please provide copies of any inter-company reports analyzing the potential of any of the listed companies to self-generate, and outlining how the Company would respond to that possibility.

HECO Response:

The following is a table of HECO's top five commercial and industrial customers for 2005 and 2006, including the percentage of HECO's total 2005 and 2006 recorded kWh electricity sales and revenues:

Rank	Description	% of Total Electricity Revenues 2005	% of Total Electricity Revenues 2006	% of Total Electricity kWh Sales 2005	% of Total Electricity kWh Sales 2006
1	Military	6.8%	6.9%	8.0%	7.7%
2	Military	3.7%	3.6%	4.1%	4.1%
3	Military	1.8%	1.9%	2.1%	2.2%
4	Local Government, Education	1.5%	1.7%	1.7%	1.7%
5	Local Government, Education	1.4%	1.4%	1.3%	1.4%

With regard to the potential of customers to self-generate, in particular with combined heat and power ("CHP") systems, please see HECO's response to DOD-IR-3-8, filed in HECO's 2005 test year rate case Docket No. 04-0113. As stated in that response, HECO assessed the potential market for new CHP installations on Oahu in its CHP Program application filed in Docket No. 03-0366. HECO's CHP forecasts, with and without utility participation in the CHP market, were provided in Exhibit A to the CHP Program application filed in Docket No. 03-0366. (A revised Exhibit A was filed December 17, 2003. A copy of Exhibit A, as revised, was attached as pages 4-10 to the response to DOD-IR-3-8.)

As HECO also stated in that response, HECO provided extensive information (i.e., testimonies, exhibits, workpapers and briefs) on DG and CHP in the DG Investigation, Docket No. 03-0371, including its assessment of the CHP market, and this information is a matter of public record.

Since that IR response was provided in Docket No. 04-0113, HECO has revised its CHP outlook for Oahu to very modest levels. This comes as a result of: 1) new rules issued by the U.S. Environmental Protection Agency ("EPA"), which will require more stringent emission controls for stationary diesel engines in the near future, 2) limitations as to the ability of HECO to provide customer-sited DG projects on a regulated utility basis, and 3) other uncertainties concerning customer-sited DG. A detailed description of these factors is provided in HECO's 2007 Adequacy of Supply ("AOS") Report, filed February 27, 2007, on page 18 and Appendix 2, pages 6-8. See also Appendix 3, page 7, regarding potential to site utility-owned DG on military sites.

With respect to the five customers listed in the table above, some accounts associated with these large customers were included, with other large customers with a demand greater than 400 kW, in HECO's assessment of the CHP market potential on Oahu. (See HECO T-1, pages 21-24, Docket No. 03-0371.) HECO also prepared, subsequent to providing the response to DOD-IR-3-8 in Docket No. 04-0113, a CHP analysis for Customer 3 in which HECO determined that CHP was not economically feasible. Customer 3 is the U.S. Air Force and includes 17 accounts, one of which is Hickam Air Force Base. HECO notified Customer 3 of the outcome of the study by letter dated April 24, 2006 (see Attachment 1), and provided the final report to Customer 3 on June 16, 2006 (see Attachment 2).

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840

Scott W. H. Seu
Manager
Energy Projects Department

April 24, 2006

Mr. Dave Stiner
Energy Manager
15 CES/CECS, 75 H St.
Hickam Air Force Base, HI 96853-5233

Dear Mr. Stiner:

We are finalizing our report on the feasibility of developing a HECO-owned combined heat and power ("CHP") system to serve the U. S. Air Force's C-17 squadron complex at Hickam Air Force Base ("HAFB"). Steve Luckett and Sam Gillie recently advised you that despite our efforts, we found the CHP system would not be feasible primarily due to poor economics. Although our feasibility report will discuss this and several other reasons for this determination in greater detail, I want to provide you with a summary of our findings regarding CHP economics.

The key challenge for CHP on the island of Oahu has been the impact of changing diesel or propane/SNG pricing. The prices for these fuels have increased significantly over the last two years and have been escalating more quickly than the low sulfur fuel oil used in our central power plants. This pricing difference means that the efficiency benefits of CHP are off-set by higher CHP fuel costs.

In the case of the HAFB CHP system, the heat recovery energy savings benefits became more limited than originally anticipated due to the elimination of a hot water wash system for the C-17 complex. Considering this and current fuel prices, our analysis shows that the HAFB CHP system would actually operate at a loss. Since petroleum prices are constantly changing, we will provide sensitivities in our study that consider different pricing scenarios. These scenarios support our conclusion.

We did consider the possibility of improving the economics of a CHP system at HAFB by using military-supplied jet fuel. The review of this alternative assumed that certain public sector fuel taxes could somehow be avoided and economies of scale could be gained via military fuel procurement. Unfortunately, we found that we could not achieve sufficient fuel cost savings to provide energy cost savings from CHP. This is consistent with findings of recent CHP studies for other customers here on Oahu. In one case, an operating CHP system has been mothballed due to unfavorable economics.

The Hawaii Public Utilities Commission ("PUC") recently provided us with guidance that HECO could pursue CHP only if it is economic and serves the interests of all our customers. The PUC provided this guidance in a very recently issued decision and order in its Distributed Generation Docket, stating that one of their fundamental policy objectives is to prevent the development of distributed generation systems that are not cost effective.

We are truly disappointed by the outcome of the study, but will continue seeking opportunities to reduce your energy costs. Should the economic viability of CHP on Oahu improve, we could again look at its feasibility. Our final report will provide a more detailed explanation of all our findings and will be available in early May. We would welcome the opportunity to brief the outcome of the study at your convenience. Our point of contact is Steve Luckett.

Despite the results of the CHP analysis, we assure you that HECO is committed to working with the Air Force on energy matters, and finding solutions that help manage your energy costs is of the utmost importance to us.

Regards,

Attachment 2 is voluminous and available for inspection at HECO's Regulatory Affairs Division Office, Suite 1301, Central Pacific Plaza, 220 South King Street, Honolulu, Hawaii. Please contact Dean Matsuura at 543-4622 to make arrangements to inspect the requested information.

Pages 21-24 and 30-34 of the attachment contain confidential information. Thus, these pages will be provided subject to Amended Protective Order No. 23378, dated June 4, 2007.

An electronic version of the requested information is being provided on a compact disc.

DOD-IR-17

If not provided in the material presented to the bond rating agencies, please provide a copy of the Company's (HECO's) most recent five-year financial forecast (or most similar document).

HECO Response:

The requested information is provided on page 2.

FORECAST: 2007 - 2011 ELECTRIC UTILITY COMPANIES

Hawaiian Electric Company, Inc. and Subsidiaries
Unaudited
Forecast as of January 31, 2007

Years ended December 31	2006	2007	2008	2009	2010	2011	2007-2011
(dollars in millions)	actual						
USES OF CAPITAL							
Transmission and distribution	$ 127.4	$ 130.4	$ 137.0	$ 116.8	$ 97.7	$ 106.5	$ 588.4
Production	53.5	77.1	139.2	105.2	74.9	76.3	472.7
General	34.0	24.7	26.2	11.0	12.4	18.0	92.3
Total capital expenditures, including AFUDC	214.9	232.2	302.4	233.0	185.0	200.8	1,153.4
Less: AFUDC	9.2	9.4	14.6	12.1	6.3	8.9	51.3
Contributions in aid of construction	35.0	23.8	28.1	21.6	22.5	20.0	116.0
Net captial expenditures	170.7	199.0	259.7	199.3	156.2	171.9	986.1
Other requirements [1]	-	-	4.4	-	-	-	4.4
Total net requirements	$ 170.7	$ 199.0	$ 264.1	$ 199.3	$ 156.2	$ 171.9	$ 990.5
SOURCES OF CAPITAL							
Internal funds after dividends							
Depreciation and amortization	$ 141.3	$ 143.9	$ 151.1	$ 156.5	$ 163.4	$ 167.4	$ 782.3
Deferred income taxes and tax credits, net	(5.9)	(7.6)	1.2	3.3	0.4	1.6	(1.1)
Retained earnings and other, excluding AFUDC	58.4	36.5	45.2	15.1	(6.8)	(10.6)	79.4
Total internal sources, excluding AFUDC	193.8	172.8	197.5	174.9	157.0	158.4	860.6
Short-term borrowings	(23.1)	(128.0)	61.3	23.9	(0.8)	13.5	(30.1)
Drawdown of revenue bond proceeds	-	154.2	5.3	0.5	-	-	160.0
External financing sources - total debt	(23.1)	26.2	66.6	24.4	(0.8)	13.5	129.9
Total sources	$ 170.7	$ 199.0	$ 264.1	$ 199.3	$ 156.2	$ 171.9	$ 990.5
Internal sources as a percent of							
Net capital expenditures	114	87	76	88	101	92	87
Total net requirements	114	87	75	88	101	92	87
CAPITAL STRUCTURE (at December 31)							
Capitalization							
Total debt	$ 879.3	$ 957.0	$ 1,023.7	$ 1,048.0	$ 1,047.2	$ 1,060.7	
Preferred stock	34.3	34.3	34.3	34.3	34.3	34.3	
Common stock [2]	958.2	1,126.5	1,206.8	1,253.3	1,270.2	1,287.1	
Total capitalization	$ 1,871.8	$ 2,117.8	$ 2,264.8	$ 2,335.6	$ 2,351.7	$ 2,382.1	
Capitalization ratios (%)							
Total debt	47.0	45.2	45.2	44.9	44.5	44.5	
Preferred stock	1.8	1.6	1.5	1.4	1.5	1.5	
Common stock	51.2	53.2	53.3	53.7	54.0	54.0	
Total capitalization	100.0	100.0	100.0	100.0	100.0	100.0	

[1] May not include those securities sold at Company's option, the proceeds of which are used to repay long-term obligations prior to their maturity.

[2] Common stock equity for 2006 includes the charges to accumulated other comprehensive income (AOCI) as a result of recording a pension and other postretirement benefits liability after implementing SFAS No. 158, on December 31, 2006.

HAWAII PUBLIC UTILITIES COMMISSION

The Governor, with the consent of the Senate, appoints three full-time commissioners to staggered six-year terms. Commissioners can serve no more than 12 consecutive years. Statutes provide for the rendering of an "interim decision" in rate cases within 11 months of the filing of a complete application by the Company. There is no statutory deadline for rendering a final decision.

Carlito P. Caliboso (an attorney previously in private practice) has been chairman of the PUC since April 30, 2003, and is serving in his second term which will expire on June 30, 2010. Also serving as commissioner is John E. Cole (term expiring June 30, 2012) who previously served as the Executive Director of the Division of Consumer Advocacy, Department of Commerce and Consumer Affairs. The other commissioner position is vacant.

CONSUMER ADVOCATE

Catherine P. Awakuni was appointed Executive Director of the Division of Consumer Advocacy effective September 18, 2006. Prior to becoming the executive director, Ms. Awakuni served as commission counsel for the Hawaii Public Utilities Commission.

DOD-IR-18

Please provide a copy of HECO's FERC Form 1 for 2006, as soon as it becomes available.

<u>HECO Response:</u>

HECO's FERC Form 1 for 2006 is voluminous and is available for inspection at HECO's Regulatory Affairs Division office, Suite 1301, Central Pacific Plaza, 220 South King Street, Honolulu, Hawaii. Please contact Dean Matsuura at 543-4622 to make arrangements to inspect the information. The FERC Form 1 for 2006 was also filed on May 14, 2007 with the Commission and the Consumer Advocate as part of its routine annual filing.

DOD-IR-19

At page 135 of Hawaiian Electric Industries 2006 S.E.C. Form 10-K, the company indicates that the expected long-term return on its retirement plan assets is 8.50% and asset mix of that portfolio is currently approximately 70% equities and 30% debt and other investments.

a) Please provide the documentation supporting that expected long-term return assessment, including long-term expectations for each class of asset in the portfolio (i.e., equities, debt, and other).

b) Please provide any internal documents prepared by the Company that support the long-term investment return expectations, as well as any such documents or studies supporting the "projected asset class returns provided by the plans' actuarial consultant."

c) Please provide a list of the equity investments included in the Company's pension plan.

HECO Response:

a. HECO objects to providing the information requested above on the grounds that the information is privileged commercial and financial information which is maintained as non-public, confidential information. Without waiving its objections, the Company submits the confidential information on page 3 pursuant to Protective Order No. 23378.

As part of the oversight process, the Pension Investment Committee ("PIC") of the Company's retirement benefit plans has periodically engaged the professional services of independent, third-party consultants to prepare asset/liability/asset allocation studies that also affirm the long-term expected rate of return assumption. The most recent study was conducted in 2004 and resulted in changes to the plans' previous strategic asset mix of 75% equities and 25% fixed income to the plans' current strategic asset mix of 70% equities and 30% fixed income.

The study used two different types of methodologies. The first method looked backwards in time and utilized the historical rates of return for various investment asset classes (with data going as far back as 1926). The second method utilized four different types of financial modeling. As part of the study, the PIC reviewed several different asset mixes before finally selecting the current strategic asset mix of 70% equities and 30% fixed income. The current strategic asset mix had been identified by the PIC as providing the best combination of expected investment return and projected total portfolio risk/volatility.

The findings of the most recent asset allocation study provided analytical support for the plans' 9% long-term rate of return assumption. The PIC reviews and adopts the major retirement benefit plan assumptions after review of current economic and asset class forecasts from various sources at the end of each financial reporting period. On December 31, 2006, based upon a review of the asset class return expectations from the Plan's consulting actuary (refer to page 3) and other sources, the long-term rate of return assumption was reduced to 8.5% from 9.0%.

b. HECO objects to providing the information requested above on the grounds that the information is privileged commercial and financial information which is maintained as non-public, confidential information. Without waiving its objections, the Company submits the confidential information on pages 4 and 5 pursuant to Protective Order No. 23378. Pages 4 and 5 are the approved minutes from the Pension Investment Committee meeting held on January 15, 2007, which adopted the expected long-term rate of return on the retirement plan assets of 8.50%.

c. HECO objects to providing the information requested on the grounds that the information is privileged commercial and financial information which is maintained as non-public, confidential information. Without waiving its objections, the Company submits the confidential information on pages 6 through 21 pursuant to Protective Order No. 23378.

Pages 3 to 21 contain confidential information and are being provided pursuant to Protective Order No. 23378, issued on April 23, 2007.

DOD-IR-20

Please provide a complete list of the cases in which Dr. Morin has presented cost of capital testimony during the past 24 months, including, the name of the utility, the jurisdiction, the type of utility operation, his recommended cost of equity.

Dr. Morin's Response:

See table below.

Company	State	Requested ROE
Delmarva (T&D elec)	Maryland	10.75-11.00
Delmarva (T&D elec)	Delaware	10.75-11.00
Potomac Elec Power (T&D elec)	Maryland	10.75-11.00
Delmarva (gas)	Delaware	11.25
Potomac Elec Power (T&D elec)	D.C.	10.75-11.00
Detroit Edison (Vert integ elec)	Michigan	11.25
Nevada Power Co (Vert integ elec)	Nevada	11.40
Puget Sound Elec (Vert integ elec)	Washington	11.25
Bangor-Hydro (T&D elec)	Maine	11.25
Entergy Arkansas (Vert integ elec)	Arkansas	11.25
Duke Kentucky (Vert integ elec)	Kentucky	11.25
Hawaiian Elec Co (Vert integ elec)	Hawaii	11.50
Hawaii Elec Lt Co (Vert integ elec)	Hawaii	11.25
Maui Elec Co (Vert integ elec)	Hawaii	11.25

DOD-IR-21

Has Dr. Morin changed the methodology used in his testimony in any way since he last testified for HECO? If so, please explain how and why the change was made.

<u>Dr. Morin's Response:</u>

No.

DOD-IR-22

[Morin Direct, p. 2, l. 3-4]

Please provide copies of each of the articles authored by Dr. Morin appearing in The Journal of Finance, The Journal of Business Administration, International Management Review, and Public Utilities Fortnightly.

Dr. Morin's Response:

Dr. Morin does not archive his authored articles dating back more than ten years, as they are available in most university libraries.

DOD-IR-23

[Morin Direct, pp. 5-6]

a. What are the consequences of allowing a return on equity that overstates the cost of capital? Is there a transfer of wealth from ratepayers to stockholders in that instance?

b. Is a goal of regulation to allow a return on common equity equal to its cost? If not, please explain why not.

<u>Dr. Morin's Response:</u>

a. Dr. Morin believes that the allowed return on equity should equal the cost of capital in order to avoid a transfer of wealth between ratepayers and shareholders. If the utility is allowed a return that is less than the cost of capital, the inevitable result is a wealth transfer from shareholders to ratepayers. Conversely, if the allowed rate of return is greater than the cost of capital, excess earnings over and above those required to service debt capital accrue to the equity holders. In this case, the wealth transfer occurs from ratepayers to shareholders. There are no wealth transfers between ratepayers and shareholders if the allowed rate of return is set equal to the cost of capital. In this case, the expected earnings generated from capital investments are sufficient to service the claims of the debt and equity holders, no more no less. Setting the allowed return equal to the cost of capital is the only policy which will produce optimal investment rates at the minimum price to the ratepayer.

b. Yes, see answer to part a.

DOD-IR-24

[Morin Direct, p. 7, ll. 16-23]

Does Dr. Morin have an opinion with regard to the relative risk of HEI and HECO? If so, which does he believe has greater risk and why. If not, please explain why he elected to analyze HECO as a stand-alone operation.

Dr. Morin's Response:

Dr. Morin did not investigate the risks of HEI, but rather focused on HECO as a stand-alone entity. Given that 84% of HEI's revenues are from regulated electric operations according to AUS Reports dated May 2007, which are submitted in response to DOD-IR-35, it is reasonable to assume that HEI and HECO reside in a similar risk class.

DOD-IR-25

[Morin Direct, pp. 10-11]

a. Is 320 US 391 the correct cite for *Hope*?

b. In the determination of the "end result test" does *Hope* offer any guidance as to firm value should be of concern to regulators? That is, if rates are reduced and firm value declines as a result, does regulation fail the end result test for that reason? Please explain your response.

Dr. Morin's Response:

a. The correct citation for Hope is 320 US 591 (1944).

b. The *Hope* case was responsible for the so-called "end result" doctrine, suggesting that the regulatory methods employed are immaterial so long as the end result is reasonable to the consumer and investor. The latter presumably implies impact on stock price. In other words, a regulator is not bound to use any single formula in determining rates. It is the result reached and the impact of the rate order rather than the method or the theory employed that is controlling.

DOD-IR-26

[Morin Direct, p. 17, f. 4]

Please provide a complete copy of the Stewart Meyers article cited.

Dr. Morin's Response:

The requested article is provided on pages 2 to 4.

Note: Most (if not all) of the information requested is copyrighted. The copy is being provided under the "fair use" exception to the copyright laws. Any copies made of the requested information are subject to copyright laws.

On the Use of Modern Portfolio Theory in Public Utility Rate Cases: Comment

Stewart C. Myers

Stewart C. Myers is Professor of Finance at the Sloan School of Management, Massachusetts Institute of Technology. *He acknowledges with thanks the helpful comments of Gerald Pogue.*

■ Sometimes procrastination helps. In this instance it allowed me to read drafts of most of the other comments on the Brigham-Crum article [1] before writing my own. The others cover most of the specific issues I would have addressed had I started from scratch. Thus relieved, I will restrict myself to five general points that express my view of the proper role of modern portfolio theory in rate of return regulation.

1. Do not reward witnesses who bury assumptions in judgment.

My first appearance as an expert witness was on behalf of the Federal Power Commission staff in 1969. I estimated the cost of equity capital for Texas Eastern Transmission Company, a gas pipeline, based on a model of the firm's stock price. During cross-examination, the company's lawyer confronted me with a list of 21 distinct assumptions that I had made in my direct testimony. I defended all of them as reasonable, but I had to admit that some of the assumptions were not literally true and that others were only "probably" or "approximately" correct.

Then the lawyer gave a little speech about the 21 assumptions, arguing that, since they could not all be correct, my estimate of the cost of equity capital was worthless.

As usual, I thought of the perfect comeback too late. I should have said: "Think of your witnesses. They only made one assumption. They assumed the answer!"

Any competent witness who uses capital market data to estimate the cost of capital is forced to reveal his or her assumptions. This creates targets of opportunity for opposing lawyers or rebuttal witnesses. Anyone who uses the Capital Asset Pricing Model (CAPM) is particularly vulnerable because that model has been the focus of so much theoretical and empirical work.

The CAPM's problems are well known. Who knows what secrets lurk in less formal and allegedly more realistic approaches?

2. Use simple models.

The best estimates of the opportunity cost of capital are still liable to measurement error. The errors come from noise in rates of return on common stocks, and from the difficulty of inferring investors' expectations from historical data. (The so-called comparable earn-s method, which does not rely on capital market a, encounters equally severe measurement blems. The method is also logically unsound. See ers [3], esp. pp. 61–63.)

The likelihood of measurement error is why honest imates of the cost of equity capital are normally en in whole percentage points — occasionally ths of a percent, but never hundredths. That is also y economists usually stick to relatively simple dels. Many refinements, although they look as if ey might capture more of reality, just lead to guments over insignificant digits.

I believe this is why the so-called DCF model is so idely used in rate cases.[1] The model assumes that in- stors forecast a perpetual and steady growth of vidends. I doubt that investors have that simple a ew of the future. The model nevertheless seems to ive reasonable answers, at least for the traditional ublic utilities in telecommunications, electric power, as pipelines, etc. Evidently firms in these industries nove slowly enough, yet at the same time have enough inancial momentum, for the DCF model to work.

Those who use beta as a risk measure do so because t is simple, objective, makes common sense, and is consistent with modern portfolio theory. They cannot say that the theory is the whole truth. They avoid fan- cier measures of risk, not out of laziness but because they try to stick to a simple measure whose properties are well understood.

3. Use more than one model when you can.

Because estimating the opportunity cost of capital is difficult, only a fool throws away useful information. That means that you should not use any one model or measure mechanically and exclusively. Beta is helpful as one tool in a kit, to be used in parallel with DCF models or other techniques for interpreting capital market data.

4. Modern portfolio theory is more than the CAPM.

The usefulness of beta as a measure of security risk does not depend on the strict validity of the CAPM. The measure can be based on the following logic.

1. Portfolio risk can be measured by σ_p, the standard deviation of portfolio return.
2. The risk of any security is its marginal contribution to σ_p. For security j, the marginal contribution is proportional to σ_{jp} or to β_{jp}, j's beta with respect to portfolio p.
3. Of course β_{jp} is different for each possible combination of portfolio and security. But the returns on any well-diversified portfolio are highly correlated with returns on the market portfolio. The bulk of capital invested in securities is invested via diversified portfolios. Thus we take the market (portfolio M) as a "standard" portfolio to proxy for investors' actual portfolios, and $\beta_j \equiv \sigma_{jM}/\sigma_M^2$ to proxy for β_{jp}.

The CAPM goes further. It says that β_j is a complete and sufficient risk measure, that the expected risk premium demanded by investors is zero when β_j is zero, and that this risk premium is linearly related to β_j. Roll shows how difficult these statements are to prove or disprove [5]. Therefore, the CAPM remains controversial. The general, qualitative tenets of modern portfolio theory are more widely accepted.

5. Beta is most useful for qualitative risk comparisons; the CAPM is also useful.

There is an unfortunate tendency to refer to any use of beta as "an application of the CAPM." Actually, one can get a good deal of mileage out of modern portfolio theory without ever using the CAPM formula for cost of equity capital estimates.

My testimony in two cases before the FCC illustrates this point [4,6]. In the 1971 AT&T case, beta was used to confirm 1) that AT&T stock was less risky than the market portfolio or a sample of large industrial companies, and 2) that AT&T's stock was just about as risky as a sample of electric utilities. The cost of equity capital estimates were obtained primarily from DCF models applied to AT&T and to the utility and industrial samples.

In the Comsat case, Gerald Pogue and I argued that Comsat common stock was significantly riskier than the typical stock in the market portfolio and *a fortiori* riskier than AT&T. Comsat had already requested a 12% equity rate of return, above the 10.5% the FCC had allowed in the prior AT&T case. The extra return had to be justified by showing that Comsat was riskier. Pogue and I showed that Comsat's beta was more than double AT&T's and that the difference was significant. We did not attempt to translate this difference into a numerical estimate of the cost of equity capital. (In both cases, the risk comparisons were repeated in terms of standard deviations of stock rates of return. The conclusions were unchanged, which I think will be the typical result in rate cases.)

As these examples illustrate, there are many ways to use betas that do not depend on the CAPM formula. Incidentally, the FCC relied on my approach in

[1]The model states that stock price equals D_1, next year's dividend, capitalized at k-g, the difference between the opportunity cost of equity capital and the growth trend of dividends. Thus k can be estimated at dividend yield plus growth: $k = D_1/P + g$.

their AT&T decision but dismissed the Myers-Pogue study with essentially no explanation.

The CAPM could have been used to generate cost of equity capital estimates for both AT&T and Comsat. That would have required stronger assumptions, although not necessarily unreasonable ones:

First, we have to accept the CAPM. This is naturally controversial. I nevertheless believe the CAPM is a reasonable theory so long as the numbers it generates are not treated as exact or conclusive. It is a rule of thumb — something worth leaning on if you don't have to lean too hard.

Second, we do not know exactly what the expected rate of return on the market portfolio is, although recent research gives an improved picture of "normal" rates of return in the U.S. economy. (See Holland and Myers [2] for evidence on "normal" rates of return and also for references to other work in this area.)

Third, standard errors of beta estimates are large for individual securities. For example, Comsat's beta was estimated at 1.69 from 6 years of monthly data, with a standard error of .30. A confidence interval including ± 2 standard errors would be $1.09 \leq \beta \leq 2.29$.[2] Estimates of *industry* betas are more accurate, providing that it is possible to obtain a sample of reasonably similar firms.

The distinction between industry and firm betas is important in rate cases. It is hard to estimate a regulated firm's cost of equity capital if data on only that firm are available. This is true regardless of the approach taken. It is necessary to broaden the sample. (See Myers [3], pp. 70–71.)

Fourth, beta may not be stable. It can be dangerous to project it from historical data. However, I believe much of the concern about instability is misplaced. Assuming a stable beta is usually no worse than assuming a constant compound growth rate for future earnings.

Conclusion

Risk comparisons are inevitable in rate of return testimony. So far, beta is the only risk measure we have that is sensible, objective, and consistent with modern portfolio theory. Clearly it should be used carefully; but so what? Any application of finance theory should be careful.

References

1. E. F. Brigham and R. L. Crum, "On the Use of the CAPM in Public Utility Rate Cases," *Financial Management* (Summer 1977), pp. 7–15.
2. D. M. Holland and S. C. Myers, "Trends in Corporate Profitability and Capital Costs," Working Paper 999–78, Sloan School of Management, M.I.T., 1978.
3. S. C. Myers, "The Application of Finance Theory in Public Utility Rate Cases," *Bell Journal of Economics and Management Science* (Spring 1972), pp. 58–97.
4. S. C. Myers and G. A. Pogue, "An Evaluation of the Risk of Comsat Common Stock," in U.S. Federal Communications Commission, Prepared Testimony S. C. Myers, F.C.C. Docket 16070, 1973.
5. R. Roll, "A Critique of the Asset Pricing Theory's Tests, Part I," *Journal of Financial Economics* (March 1977), pp. 129–76.
6. U.S. Federal Communications Commission, American Telephone and Telegraph Company, Prepared Testimony S. C. Myers, F.C.C. Docket 19129, 1971.

[2] Yet Comsat's beta was so far above 1.0 or AT&T's beta that Pogue and I were able to establish our point despite the high standard error of the estimate. The Comsat case was a rare opportunity because there was such a dramatic spread between its risk and AT&T's.

DOD-IR-27

[Morin Direct, p. 18, citing Phillips]

a. Does Dr. Phillips also comment on the reliability of the Risk Premium method?

b. If so, please explain why Dr. Morin elected to cite only Phillips' comments regarding the DCF, and eliminate the other comments of a "leading expert in regulation."

c. What is Dr. Phillips' preferred method of equity cost estimation?

Dr. Morin's Response:

a. Yes. Moreover, while most, if not all, college-level corporate finance textbooks devote the vast majority of their cost of capital coverage to asset pricing models, such as the CAPM, Fama-French version of the CAPM, and the Arbitrage Pricing Model, considerably less attention is devoted to the DCF model's limitations.

b. Dr. Phillips' comments on the DCF are shown on pages 17-18 of Dr. Morin's direct testimony. Dr. Phillips also discusses the dangers of relying solely on the CAPM model because of the stringency of certain of its underlying assumptions, as is the case for any model in the social sciences. As noted by Dr. Morin on page 18 of his testimony, Dr. Phillips deals with the reliability of the CAPM in a few paragraphs on Pages 376-377 of his book. Pages 17-19 of Dr. Morin's direct testimony deal specifically with the dangers of relying on the DCF model and the lack of realism of its underlying assumptions when applied to the fast-changing electric utility industry. Dr. Morin is well aware that caution and judgment are required when relying on any model in the social sciences, including financial models such as the CAPM. Models represent simplified abstractions of reality so as to improve our understanding of socio-economic phenomena. In the case of financial models, the DCF model is particularly sensitive to fundamental and structural changes, for it assumes constant infinite growth in book value, earnings, dividends, and stock price forever.

Sole reliance on the DCF model simply ignores the capital market evidence and investors' use of other theoretical frameworks such as the Risk Premium and CAPM methodologies. The DCF model is only one of many tools to be employed to estimate the cost of equity. It is not a superior methodology which supplants other financial theory and market evidence. The same is true of the CAPM.

c. Given Dr. Phillips' exposition of all the various methods of specifying a fair return, including DCF, CAPM, Risk Premium, Comparable Earnings, and Interest Coverage, it is reasonable to conclude that Dr. Phillips's preference is to rely on all the various methods.

DOD-IR-28

[Morin Direct, p. 19, ll. 1-4]

a. Please provide support from the financial literature on which the DCF is based (e.g., Williams (1938), Gordon (1962), Gordon (1974), or any other source Dr. Morin believes to be seminal to the DCF) that supports the contention that the DCF provides an accurate estimate of the cost of equity "only when stock price and book value are reasonably similar."

b. Please quantify the term "reasonably similar."

Dr. Morin's Response:

a. See Dr. Morin's 1984, 1994, and 2006 textbooks on the subject:

   Morin, R.A. *Utilities' Cost of Capital,* Arlington, VA: Public Utilities Reports, Inc., 1984.

   Morin, R.A. *Regulatory Finance,* Arlington, VA: Public Utilities Reports, Inc., 1994.

   Morin, R.A. *The New Regulatory Finance,* Arlington, VA: Public Utilities Reports, Inc., 1994.

b. Please see response to item a above.

DOD-IR-29

[Morin Direct, p. 19, ll. 4-12]

a. Do the CAPM and Risk Premium provide market-based equity cost estimates? If not, please explain why not.

b. In regulation, are market-based equity cost estimates provided by CAPM and Risk Premium methods applied to book value rate base and capital structures? If not, please provide examples from regulatory orders to support your response.

c. Please explain whether or not the CAPM and Risk Premium are able to provide reasonable equity cost estimates when market prices are not "reasonably similar" to book value.

Dr. Morin's Response:

a. Yes.

b. The current cost of attracting capital is measured by reference to market values. The DCF test measures directly the return that investors require on the market value of the equity. For a utility regulated on book value rate base, the current cost of attracting equity capital is only equivalent to the return investors require on book value when the market value of the common stock is equal to its book value. As the market value of the equity of regulated utilities increases above its book value, the application of a market-value derived cost of equity to the book value of that equity increasingly understates investors' return requirements (in dollar terms). In contrast, the CAPM and Risk Premium tests do not rely directly on the market value of the equity but rather on relative risk differentials between stocks and bonds.

c. See Dr. Morin's response to item b above.

DOD-IR-30

[Morin Direct, pp. 20, 21]

Does Dr. Morin use quarterly dividend compounding in his DCF analysis in every jurisdiction in which he testifies? If not, why not; and if not, please provide a complete copy of the most recent cost of capital testimony filed by Dr. Morin in which he did not use quarterly compounding in his DCF analysis.

Dr. Morin's Response:

One of the assumptions of the standard DCF model is that dividend payments are made at the end of each year, whereas, in fact, most utilities pay dividends on a quarterly basis.[1] Chapter 11 of Dr. Morin's book, The New Regulatory Finance, provides a full discussion, derivation, and implementation of the quarterly DCF model in regulatory hearings.

When applying the DCF model to utility stocks, Dr. Morin relies on the annual form of the DCF model in most jurisdictions that employ forward test years. In the usual case of a forward test year, the use of the nominal return is preferable to the use of the effective return. This is because in the case of a forward test year for a growing utility, the equity balance at the end of the test period exceeds the equity balance at the beginning of the test period. Applying the effective return from the quarterly DCF model to the average equity balance will produce a higher actual effective return to the investor. Therefore, in jurisdictions with a forward test period and for a utility with a growing rate base, the use of a nominal return is preferable. Authorizing the nominal return from the quarterly DCF model yields a return comparable to the effective return from that model. The reverse is true in the case of a historical test year or a utility with a declining rate base. In jurisdictions where a historical test period is used, the use of the effective return is highly preferable

[1] D_1 can be interpreted as either the dividends paid during the next period or as the dividend rate at the end of the next period. Although the former is more within the spirit of the DCF model, in practice, the two interpretations differ by a very small amount so that the issue is not problematic.

and will in fact produce a downward-biased estimate of the investor's required return. The use of the effective return will produce a fair return to the investor in the case of a current test year jurisdiction. For testimony in which Dr. Morin did not use quarterly compounding in his DCF analysis, see his Rate of Return on Common Equity testimony, MECO T-16, in Maui Electric Company, Ltd. 2007 Test Year Rate Case, Docket No. 2006-0387.

When applying the model to unregulated entities or market aggregates, the issue of rate base is moot, and the quarterly DCF model is clearly applicable.

DOD-IR-31

[Morin Direct, p. 21, ll. 11-13]

a. Please provide a complete copy of the NARUC survey to which Dr. Morin refers.

b. In that survey, how many regulatory bodies listed the DCF as a cost of capital methodology they used?

c. How many listed the CAPM?

d. How many listed Risk Premium?

Dr. Morin's Response:

a. The requested article is provided on pages 2 to 12.

b. See the document provided in response to item a. above.

c. See the document provided in response to item a. above.

d. See the document provided in response to item a. above.

Note: Most (if not all) of the information requested is copyrighted. The copy is being provided under the "fair use" exception to the copyright laws. Any copies made of the requested information are subject to copyright laws.

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TABLE 114 - AGENCY AUTHORITY OVER RATE OF RETURN - TELEPHONE UTILITIES

AGENCY	Agency determines rate of return under its general authority	Capital structure is adjusted to exclude non-utility financing when it is traceable	Method Agency favors in determining rate of return: No ONE method ALL are considered	** Discounted cash flow	** Comparable earnings test	** Earnings/price ratio	** Midpoint approach	** Capital asset pricing model	** Risk premium	Other	Duration of call protection provision influences judgment in determining rate of return
FCC	X	X	X 2/								
ALABAMA PSC 15/	X	X		X							
ALASKA PUC	X	X			X						Possible.
ARIZONA CC	X	X	X 2/	X 6/							
ARKANSAS PSC	X		X	X 10/							
CALIFORNIA PUC	X	X 1/	X 2/	X	X			X	X	X	Possible.
COLORADO PUC	X	X		X 8/	X						
CONNECTICUT DPUC	X	X		X							
DELAWARE PSC	X		X 2/	X	X					X	
D.C. PSC	X	X		X							
FLORIDA PSC	X	X 1/	X 2/								
GEORGIA PSC	X	X	X 2/	X					X	X 7/	
HAWAII PUC	X	X	X 2/		X					X	
IDAHO PUC	X	X		X 8/	X	X					
ILLINOIS CC	X	X	X 2/				X			X	
INDIANA URC	X		X								
IOWA UB	X	X 1/	X	X					X	X 5/	
KANSAS SCC	X	X		X							
KENTUCKY PSC	X	X	X 2/	X	X	X	X			X	
LOUISIANA PSC	X			X							
MAINE PUC	X	9/	X 8/	X							
MARYLAND PSC	X	X		X						X 5/	
MASSACHUSETTS DPU	X	X		X 6/						X 4/	
MICHIGAN PSC	X	X	2/	X	X		X	X	X	X	
MINNESOTA PUC	X	X		X							
MISSISSIPPI PSC	X	X		X	X						
MISSOURI PSC	X	X		X							
MONTANA PSC	X	X		X	X						
NEBRASKA PSC	X	X		X							
NEVADA PSC	X	X		X	X	X					
NEW HAMPSHIRE PUC	X	X		X							Yes
NEW JERSEY BPU 15/	X	X	X					X	X	X	
NEW MEXICO SCC	X		X				X				
NEW YORK PSC	X	X	X	X 6/						X	
NORTH CAROLINA UC	X	X	X 2/	X	X			X	X	X	
NORTH DAKOTA PSC 11/											
OHIO PUC	X	X	X	X 6/				X	X	X 6/	No decision.
OKLAHOMA CC	X	X		X	X			X	X		
OREGON PUC	X	X 1/		X				X			
PENNSYLVANIA PUC	X	X	X 2/	X	X	X	X			X	Maybe, if soon
RHODE ISLAND PUC	X	X	X	X	X					X 3/	
SOUTH CAROLINA PSC	X	X	X	X				X	X		
SOUTH DAKOTA PUC	X	X		X	X						
TENNESSEE PSC	X	X	X 2/	X	X	X	X	X	X		
TEXAS PUC	X	X	X 2/	X	X				X	X	
UTAH PSC	X	X		X							
VERMONT PSB 15/	X	X		X	X					X	
VIRGINIA SCC 12/	X	X							X		
WASHINGTON UTC	X	X		X							
WEST VIRGINIA PSC	X	X	X 2/	X	X			X	X	X	
WISCONSIN PSC	X 13/	X 14/	X 2/	X				X		X	
WYOMING PSC	X		X 2/	X	X			X	X	X	
PUERTO RICO PSC 15/	X	X			X						
VIRGIN ISLANDS PSC	X	9/	X 2/	X	X					X	
CANADIAN RTC	X		X 2/	X	X					X	

** For definitions of terms, please consult the Glossary of Terms at the back of this book. ICB = Case-by-Case Basis

FOOTNOTES - TABLE 114
AGENCY AUTHORITY OVER RATE OF RETURN

1/ Non-utility investment dollars are always excluded from rate base. Where non-utility investment is comparatively small, capital ratios are not adjusted. When non-utility investment is large, we usually remove non-utility investment from equity.

2/ Commission favors no single method, but rather that which produces the most reasonable results.

3/ It may use any method it desires especially in the case of a small company.

4/ DCF is preferred, but Department approves other methods which check DCF result; risk spread analysis preferred by a slight margin. Financial condition of utility also given serious consideration.

5/ DCF is preferred; all methods are considered including econometric modeling approach.

6/ No single method, however, discounted cash flow is frequently used.

7/ Discounted cash flow most often used, but risk premium method used also. Determined case by case.

8/ DCF has been the preferred method, but its results should be checked with other methods.

9/ Never an issue before this agency.

10/ Agency favors DCF, but any method presented is considered.

11/ Telephone not subject to rate of return regulation.

12/ In Case No. PUC930036, Commission authorized company-specific price index plans, a company-specific rate of return plan, and a generic rate of return (Earnings Incentive) plan. Both rate of return plans incorporate a risk premium methodology to annually establish a 300 basis point range for ROE which is 10.96-13.96 for 1995.

13/ Effective 1/1/94, telephone utilities may elect to become price-regulated in lieu of rate of return regulated. Ameritech-Wisconsin and GTE North have made this price-regulation election.

14/ Non-utility investment dollars are removed from equity.

15/ Commission did not respond to request for update information; this data may not be current.

TABLE 249 - AGENCY AUTHORITY OVER RATE OF RETURN - ELECTRIC UTILITIES

AGENCY	Agency determines rate of return under its general authority	Capital structure is adjusted to exclude non-utility financing when it is traceable	Method Agency favors in determining rate of return								Duration of call protection provision influences judgment in determining rate of return
			No ONE method ALL are considered	** Discounted cash flow	** Comparable earnings test	** Earnings/price ratio	** Mid-point approach	** Capital asset pricing model	** Risk premium	Other	
FERC	X	X	X	X							
ALABAMA PSC	X	X		X							
ALASKA PUC	X	X			X						Possible.
ARIZONA CC	X	X	X 2/	X 7/							
ARKANSAS PSC	X		X	X 11/							
CALIFORNIA PUC	X	X 1/	X 2/	X	X			X	X	X	Possible.
COLORADO PUC	X	X		X 9/	X						
CONNECTICUT DPUC	X	X		X							
DELAWARE PSC	X		X 2/	X	X					X	
D.C. PSC	X	X		X							
FLORIDA PSC	X	X 1/	X 2/								
GEORGIA PSC	X	X	X 2/	X					X	X 8/	
HAWAII PUC	X	X	X 2/		X					X	
IDAHO PUC	X	X		X 9/	X	X					
ILLINOIS CC	X	X	X 2/				X			X	
INDIANA URC	X		X								
IOWA US	X	X 1/	X	X					X	X 6/	
KANSAS SCC	X	X		X							
KENTUCKY PSC	X	X	X 2/	X	X	X	X			X	
LOUISIANA PSC	X			X							
MAINE PUC	X	10/	X 9/	X							
MARYLAND PSC	X	X		X						X 6/	
MASSACHUSETTS DPU	X	X		X 5/						X 5/	
MICHIGAN PSC	X	X	2/	X	X		X	X	X	X	
MINNESOTA PUC	X	X		X							
MISSISSIPPI PSC	X	X		X	X						
MISSOURI PSC	X	X		X							
MONTANA PSC	X	X		X	X						
NEBRASKA PSC 4/											
NEVADA PSC	X	X		X	X	X					
NEW HAMPSHIRE PUC	X	X		X							Yes
NEW JERSEY BPU 12/	X	X	X					X	X	X	
NEW MEXICO PUC	X	X	X 2/	X						X	
NEW YORK PSC	X	X	X	X 7/						X	
NORTH CAROLINA UC	X	X	X 2/	X	X			X	X	X	
NORTH DAKOTA PSC	X			X							
OHIO PUC	X	X	X	X 7/						X 7/	No decision.
OKLAHOMA CC	X	X		X	X			X	X		
OREGON PUC	X	X 1/		X				X			
PENNSYLVANIA PUC	X	X	X 2/	X	X	X	X			X	Maybe, if soon
RHODE ISLAND PUC	X	X	X	X	X					X 3/	
SOUTH CAROLINA PSC	X	X	X	X				X	X		
SOUTH DAKOTA PUC	X	X		X	X						
TENNESSEE PSC	X	X	X 2/	X	X	X	X	X	X		
TEXAS PUC	X	X	X 2/	X	X				X	X	
UTAH PSC	X	Y		X							
VERMONT PSB 12/	X	X		X	X					X	
VIRGINIA SCC	X	X	X 2/								
WASHINGTON UTC	X	X		X							
WEST VIRGINIA PSC	X	X	X 2/	X	X			X	X	X	
WISCONSIN PSC	X	X	X 2/	X				X		X	
WYOMING PSC	X		X 2/	X	X			X	X	X	
PUERTO RICO PSC	Does not regulate electric utilities.										
VIRGIN ISLANDS PSC	X	10/	X 2/	X	X					X	
ALBERTA EUB	X	X	X 2/	X	X					X	
NOVA SCOTIA UARB	X	X	X 2/	X	X				X	X	
ONTARIO EB 12/	X	X	X 2/		X					X	

** For definitions of terms, please consult the Glossary of Terms at the back of this book. ICB = Case-by-Case Basis

FOOTNOTES - TABLE 249
AGENCY AUTHORITY OVER RATE OF RETURN

1/ Non-utility investment dollars are always excluded from rate base. Where non-utility investment is comparatively small, capital ratios are not adjusted. When non-utility investment is large, we usually remove non-utility investment from equity.

2/ Commission favors no single method, but rather that which produces the most reasonable results.

3/ It may use any method it desires especially in the case of a small company.

4/ No Commission regulation of electric or gas utilities.

5/ DCF is preferred, but Department approves other methods which check DCF result; risk spread analysis preferred by a slight margin. Financial condition of utility also given serious consideration.

6/ DCF is preferred; all methods are considered including econometric modeling approach.

7/ No single method, however, discounted cash flow is frequently used.

8/ Discounted cash flow most often used, but risk premium method used also. Determined case by case.

9/ DCF has been the preferred method, but its results should be checked with other methods.

10/ Never an issue before this agency.

11/ Agency favors DCF, but any method presented is considered.

12/ Commission did not respond to request for update information; this data may not be current.

TABLE 291 - AGENCY AUTHORITY OVER RATE OF RETURN - GAS UTILITIES

AGENCY	Agency determines rate of return under its general authority	Capital structure is adjusted to exclude non-utility financing when it is traceable	Method Agency favors in determining rate of return: No ONE method ALL are considered	** Discounted cash flow	** Comparable earnings test	** Earnings/price ratio	** Midpoint approach	** Capital asset pricing model	** Risk premium	Other	Duration of call protection provision influences judgment in determining rate of return
FERC	X	X	X	X							
ALABAMA PSC 12/	X	X		X							
ALASKA PUC	X	X			X						Possible.
ARIZONA CC	X	X	X 2/	X 7/							
ARKANSAS PSC	X		X	X 11/							
CALIFORNIA PUC	X	X 1/	X 2/	X	X			X	X	X	Possible.
COLORADO PUC	X	X		X 9/	X						
CONNECTICUT DPUC	X	X		X							
DELAWARE PSC	X		X 2/	X	X					X	
D.C. PSC	X	X		X							
FLORIDA PSC	X	X 1/	X 2/								
GEORGIA PSC	X	X	X 2/	X					X	X 8/	
HAWAII PUC	X	X	X 2/		X					X	
IDAHO PUC	X	X		X 9/	X	X					
ILLINOIS CC	X	X	X 2/				X			X	
INDIANA URC	X		X								
IOWA UB	X	X 1/	X	X					X	X 6/	
KANSAS SCC	X	X		X							
KENTUCKY PSC	X	X	X 2/	X	X	X	X			X	
LOUISIANA PSC	X			X							
MAINE PUC	X	10/	X 9/	X							
MARYLAND PSC	X	X		X						X 6/	
MASSACHUSETTS DPU	X	X		X 5/						X 5/	
MICHIGAN PSC	X	X	2/	X	X		X	X	X	X	
MINNESOTA PUC	X	X		X							
MISSISSIPPI PSC	X	X		X	X						
MISSOURI PSC	X	X		X							
MONTANA PSC	X	X		X	X						
NEBRASKA PSC 4/											
NEVADA PSC	X	X		X	X	X					
NEW HAMPSHIRE PUC	X	X		X							Yes
NEW JERSEY BPU 12/	X	X	X					X	X	X	
NEW MEXICO PUC	X	X	X 2/	X						X	
NEW YORK PSC	X	X	X	X 7/						X	
NORTH CAROLINA UC	X	X	X 2/	X	X			X	X	X	
NORTH DAKOTA PSC	X			X							
OHIO PUC	X	X	X	X 7/						X 7/	No decision.
OKLAHOMA CC	X	X		X	X			X	X		
OREGON PUC	X	X 1/		X				X			
PENNSYLVANIA PUC	X	X	X 2/	X	X	X	X			X	Maybe, if soon
RHODE ISLAND PUC	X	X	X	X	X					X 3/	
SOUTH CAROLINA PSC	X	X	X	X				X	X		
SOUTH DAKOTA PUC	X	X		X	X						
TENNESSEE PSC	X	X	X 2/	X	X	X	X	X	X		
TEXAS RC	X	X	X 2/	X					X		
UTAH PSC	X	X		X							
VERMONT PSB 12/	X	X		X	X					X	
VIRGINIA SCC	X	X	X 2/								
WASHINGTON UTC	X	X		X							
WEST VIRGINIA PSC	X	X	X 2/	X	X			X	X	X	
WISCONSIN PSC	X	X	X 2/	X				X		X	
WYOMING PSC	X		X 2/	X	X			X	X	X	
PUERTO RICO PSC 12/	X	X			X						
VIRGIN ISLANDS PSC	X	10/	X 2/	X	X					X	
NAT'L ENERGY BOARD	X	X	X 2/	X	X			X	X	X	
ALBERTA EUB	X	X	X 2/	X	X					X	
ONTARIO EB 12/	X	X	X 2/		X					X	
QUEBEC NGB	X	X	X 2/							X	

** For definitions of terms, please consult the Glossary of Terms at the back of this book. ICB = Case-by-Case Basis

FOOTNOTES - TABLE 291
AGENCY AUTHORITY OVER RATE OF RETURN - GAS UTILITIES

1/ Non-utility investment dollars are always excluded from rate base. Where non-utility investment is comparatively small, capital ratios are not adjusted. When non-utility investment is large, we usually remove non-utility investment from equity.

2/ Commission favors no single method, but rather that which produces the most reasonable results.

3/ It may use any method it desires especially in the case of a small company.

4/ No Commission regulation of electric or gas utilities.

5/ DCF is preferred, but Department approves other methods which check DCF result; risk spread analysis preferred by a slight margin. Financial condition of utility also given serious consideration.

6/ DCF is preferred; all methods are considered including econometric modeling approach.

7/ No single method, however, discounted cash flow is frequently used.

8/ Discounted cash flow most often used, but risk premium method used also. Determined case by case.

9/ DCF has been the preferred method, but its results should be checked with other methods.

10/ Never an issue before this agency.

11/ Agency favors DCF, but any method presented is considered.

12/ Commission did not respond to request for update information; this data may not be current.

TABLE 308 - AGENCY AUTHORITY OVER RATE OF RETURN - WATER UTILITIES

AGENCY	Agency determines rate of return under its general authority	Capital structure is adjusted to exclude non-utility financing when it is traceable	Method Agency favors in determining rate of return								Duration of call protection provision influences judgment in determining rate of return
			No ONE method ALL are considered	** Discounted cash flow	** Comparable earnings test	** Earnings/price ratio	** Midpoint approach	** Capital asset pricing model	** Risk premium	Other	
ALABAMA PSC 11/	X	X		X							
ALASKA PUC	X	X			X						Possible.
ARIZONA CC	X	X	X 2/	X 6/							
ARKANSAS PSC	X		X	X 9/							
CALIFORNIA PUC	X	X 1/	X 2/	X	X			X	X	X	Possible.
COLORADO PUC	X	X		X 7/	X						
CONNECTICUT DPUC	X	X		X							
DELAWARE PSC	X		X 2/	X	X					X	
D.C. PSC	DOES NOT REGULATE										
FLORIDA PSC	X	X 1/	X 2/								
GEORGIA PSC	DOES NOT REGULATE										
HAWAII PUC	X	X	X 2/		X					X	
IDAHO PUC	X	X		X 7/	X	X					
ILLINOIS CC	X	X	X 2/				X			X	
INDIANA URC	X		X								
IOWA UB	X	X 1/	X	X					X	X 5/	
KANSAS SCC	X	X		X							
KENTUCKY PSC	X	X	X 2/	X	X	X	X			X	
LOUISIANA PSC	X			X							
MAINE PUC	X	8/	X 7/	X							
MARYLAND PSC	X	X		X						X 5/	
MASSACHUSETTS DPU	X	X		X 4/						X 4/	
MICHIGAN PSC	X	X	2/	X	X		X	X	X	X	
MINNESOTA PUC	DOES NOT REGULATE										
MISSISSIPPI PSC	X	X		X	X						
MISSOURI PSC	X	X		X							
MONTANA PSC	X	X		X	X						
NEBRASKA PSC	X	X	X								
NEVADA PSC	X	X		X	X	X					
NEW HAMPSHIRE PUC	X	X		X							Yes
NEW JERSEY BPU 11/	X	X	X					X	X	X	
NEW MEXICO PUC	X	X	X 2/	X						X	
NEW YORK PSC	X	X	X	X 6/						X	
NORTH CAROLINA UC	X	X	X 2/	X	X			X	X	X	
NORTH DAKOTA PSC	DOES NOT REGULATE										
OHIO PUC	X	X	X	X 6/						X 6/	No decision.
OKLAHOMA CC	X	X	X 2/	X						X	
OREGON PUC	X	X 1/		X				X			
PENNSYLVANIA PUC	X	X	X 2/	X	X	X	X			X	Maybe, if soon
RHODE ISLAND PUC	X	X	X	X	X					X 3/	
SOUTH CAROLINA PSC	X	X	X	X				X	X		
SOUTH DAKOTA PUC	DOES NOT REGULATE										
TENNESSEE PSC	X	X	X	X	X	X	X	X	X		
TEXAS NRCC	X	X							X		
UTAH PSC	X	X		X							
VERMONT PSB 11/	X	X		X	X					X	
VIRGINIA SCC	X	X	X 2/								
WASHINGTON UTC	X	X		X							
WEST VIRGINIA PSC	X	X	X 2/	X	X			X	X	X	
WISCONSIN PSC	X	X	X 2/	X				X		X	
WYOMING PSC	X	ICB	X 2/	X	X			X		X 10/	
PUERTO RICO PSC 11/	X	X			X						
VIRGIN ISLANDS PSC	X	8/	X 2/	X	X					X	
ALBERTA EUB	X	X	X 2/	X	X					X	
NOVA SCOTIA UARB	X	X	X 2/	X	X				X	X	

** For definitions of terms, please consult the Glossary of Terms at the back of this book. ICB=Case-by-Case Basis

FOOTNOTES - TABLE 308
AGENCY AUTHORITY OVER RATE OF RETURN

1/ Non-utility investment dollars are always excluded from rate base. Where non-utility investment is comparatively small, capital ratios are not adjusted. When non-utility investment is large, we usually remove non-utility investment fro ity.
2/ Commission favors no single method, but rather that which produces the most reasonable results.
3/ It may use any method it desires especially in the case of a small company.
4/ DCF is preferred, but Department approves other methods which check DCF result; risk spread analysis preferred by a slight margin. Financial condition of utility also given serious consideration.
5/ DCF is preferred; all methods are considered including econometric modeling approach.
6/ No single method, however, discounted cash flow is frequently used.
7/ DCF has been the preferred method, but its results should be checked with other methods.
8/ Never an issue before this agency.
9/ Agency favors DCF, but any method presented is considered.
10/ Most jurisdictional water operations are so small an operation ratio or cash flow basis is used rather than a ROR determination.
11/ Commission did not respond to request for update information; this data may not be current.

DOD-IR-32

[Morin Direct, p. 22]

Does the Indiana Utility Regulatory Commission continue to use the DCF in the determination of the cost of equity to be allowed regulated utilities? Please provide support for your response.

Dr. Morin's Response:

According to the NARUC survey document provided in response to DOD-IR-31, the Indiana Utility Regulatory Commission relies on the results of all methods.

DOD-IR-33

[Morin Direct, p. 22, f. 7]

Please provide a complete copy of the Bruner article cited.

<u>Dr. Morin's Response:</u>

The requested article was provided in response to CA-RIR-17 filed on April 22, 2005 in Docket No. 04-0113.

DOD-IR-34

[Morin Direct, p. 23, ll. 15-16]

Would Dr. Morin agree that "several fundamental structural changes have transformed the electric utility industry since the CAPM and its assumptions were developed."? If not, please explain why not; if so, please explain why that fact would not also make the CAPM unreliable.

Dr. Morin's Response:

Dr. Morin agrees that several fundamental structural changes have transformed the electric utility industry since the CAPM was developed. The DCF model is particularly sensitive to these fundamental and structural industry changes, for it assumes constant infinite growth in book value, earnings, dividends, and stock price forever. The assumptions underlying the CAPM are far less stringent, however, and the model can accommodate structural changes in input parameters, such as beta.

DOD-IR-35

[Morin Direct, p. 25, ll. 1-9]

Please provide the supporting data for each year for the graph on page 25 in spreadsheet format. Please also list the companies that are included in the industry aggregate.

Dr. Morin's Response:

The electric utility industry P/E ratios for each year are drawn directly from the monthly editions of the C. A. Turner (now AUS) Utility Reports, and are industry averages. The relevant portion of the latest edition is provided on pages 2 to 5. The companies covered are listed in the publication. Data for the years 1990 – 1996 can be obtained from reports for that time period.

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REPORT PAGES

ELECTRIC COMPANIES

	COMPANY	% ELEC REV	S&P BOND RATING	MOODY'S BOND RATING	COMMON EQUITY RATIO (3)	REGULATION ALLOWED ROE
1	Allegheny Energy, Inc. (NYSE-AYE)	81	BBB-	Baa3	36	10.73
2	ALLETE, Inc. (NYSE-ALE)	83	A	Baa1	63	11.60
3	American Electric Power Co. (NYSE-AEP)	94	BBB	Baa1	43	11.05
4	Central Vermont Public Serv. Corp. (NYSE-CV)	100	BBB	NR	58	10.75
5	Cleco Corporation (NYSE-CNL)	96	BBB	Baa1	56	11.25
6	DPL Inc.(NYSE-DPL)	100	BBB	NR	28	11.00
7	Duquesne Light Holdings Inc. (NYSE-DQE)	78	BBB+	Baa1	35	-
8	Edison International (NYSE-EIX)	82	BBB+	Baa1	42	11.60
9	El Paso Electric Company (ASE-EE)	97	BB-	Ba1	49	11.25
10	FirstEnergy Corporation (NYSE-FE)	85	BBB	Baa1	44	9.75
11	FPL Group, Inc. (NYSE-FPL)	76	A	Aa3	45	11.75
12	Great Plains Energy Incorporated (NYSE-GXP)	43	BBB	A3	50	-
13	Hawaiian Electric Industries, Inc. (NYSE-HE)	84	BBB	Baa2	27	10.82
14	IDACORP, Inc. (NYSE-IDA)	99	A-	A3	49	-
15	Maine & Maritimes Corporation (ASE-MAM)	86	NR	NR	46	10.20
16	OGE Energy Corp. (NYSE-OGE)	43	BBB +	Baa2	54	10.38
17	Otter Tail Corporation (NDQ-OTTR)	27	BBB+	A3	61	12.00
18	Pinnacle West Capital Corp. (NYSE-PNW)	77	BBB-	Baa2	51	10.25
19	Progress Energy Inc. (NYSE-PGN)	86	BBB	A3	47	12.42
20	Southern Company (NYSE-SO)	98	A	A2	43	12.20
21	TXU Corp. (NYSE-TXU)	23	BBB-	Baa2	15	11.25
22	UIL Holdings Corporation (NYSE-UIL)	90	NR	Baa2	49	9.75
23	Westar Energy, Inc. (NYSE-WR)	72	BB+	Baa3	50	10.00
	AVERAGE				45	11.00

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REPORT PAGES

COMBINATION ELECTRIC & GAS COMPANIES

	COMPANY	% ELEC REV	S&P BOND RATING	MOODY'S BOND RATING	COMMON EQUITY RATIO (3)	REGULATION ALLOWED ROE
1	AES Corporation (NYSE-AES)	50	BBB-	Baa1	12	-
2	Alliant Energy Corporation (NYSE-LNT)	73	A-	A2	81	11.02
3	Ameren Corporation (NYSE-AEE)	81	BBB	Baa1	50	10.42
4	Aquila Inc. (NYSE-ILA)	56	B	B2	48	10.77
5	Avista Corporation (NYSE-AVA)	50	BBB-	Baa3	45	10.40
6	Black Hills Corporation (NYSE-BKH)	29	BBB	Baa1	50	-
7	CenterPoint Energy (NYSE-CNP)	19	BBB	Baa2	14	10.14
8	CH Energy Group, Inc. (NYSE-CHG)	51	A	A2	56	9.60
9	CMS Energy Corporation (NYSE-CMS)	48	BBB-	Baa2	23	11.08
10	Consolidated Edison, Inc. (NYSE-ED)	63	A	A1	47	10.87
11	Constellation Energy Group, Inc. (NYSE-CEG)	11	BBB+	Baa2	46	11.00
12	Dominion Resources, Inc. (NYSE-D)	33	BBB+	Baa1	39	10.50
13	DTE Energy Company (NYSE-DTE)	53	BBB+	A3	39	11.00
14	Duke Energy Corporation (NYSE-DUK)	50	BBB+	A2	55	11.18
15	Empire District Electric Co. (NYSE-EDE)	91	BBB+	Baa1	48	10.90
16	Energy East Corporation (NYSE-EAS)	58	BBB+	A3	41	10.69
17	Entergy Corporation (NYSE-ETR)	83	BBB-	Baa2	47	10.97
18	Exelon Corporation (NYSE-EXC)	67	BBB	Baa1	43	10.05
19	Florida Public Utilities Company (ASE-FPU)	36	NR	Aaa	46	11.28
20	Integrys Energy Group (NYSE-TEG)	16	A+	Aa2	42	11.21
21	MDU Resources Group, Inc. (NYSE-MDU)	5	A-	A2	63	11.83
22	MGE Energy, Inc. (NDQ-MGEE)	63	AA-	Aa3	55	11.00
23	NiSource Inc. (NYSE-NI)	17	BBB	Baa2	44	11.75
24	Northeast Utilities (NYSE-NU)	77	BBB	Baa1	40	9.81
25	Northwestern Corporation (NYSE-NWEC)	58	BB+	Baa3	50	11.46
26	NSTAR (NYSE-NST)	81	A+	A1	34	12.50
27	Pepco Holdings, Inc. (NYSE-POM)	58	BBB+	Baa1	42	10.26
28	PG&E Corporation (NYSE-PCG)	70	BBB	Baa1	43	11.35
29	PNM Resources, Inc. (NYSE-PNM)	79	BBB	Baa2	40	10.33
30	PPL Corporation (NYSE-PPL)	66	A-	A3	38	9.57
31	Public Service Enterprise Group (NYSE-PEG)	61	A-	A3	37	9.88
32	Puget Energy, Inc. (NYSE-PSD)	61	BBB	Baa2	38	10.40
33	SCANA Corporation (NYSE-SCG)	41	A-	A1	43	10.71
34	SEMPRA Energy (NYSE-SRE)	40	A+	A1	87	10.70
35	Sierra Pacific Resources (NYSE-SRP)	94	BB+	Ba1	39	10.48
36	TECO Energy, Inc. (NYSE-TE)	60	BBB-	Baa2	31	11.25
37	UniSource Energy Corporation (NYSE-UNS)	85	BBB-	Baa2	35	10.67
38	Unitil Corporation (ASE-UTL)	86	NR	NR	37	9.84
39	Vectren Corporation (NYSE-VVC)	21	A	A3	41	11.03
40	Wisconsin Energy Corporation (NYSE-WEC)	63	A-	A1	40	11.20
41	Xcel Energy Inc. (NYSE-XEL)	77	BBB+	A3	44	11.05
	AVERAGE				44	0.00

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COMPOSITE INDEX

ELECTRIC COMPANIES

		DIVIDEND YIELD	PRICE EARNINGS MULTIPLE
YEAR	1997	6.1	13.3
YEAR	1998	4.8	16.6
YEAR	1999	4.8	15.2
YEAR	2000	5.4	13.6
YEAR	2001	4.5	14.0
YEAR	2002	5.0	14.8
YEAR	2003	5.0	15.4
YEAR	2004	4.4	18.4
YEAR	2005	4.1	20.9
YEAR	2006	3.8	20.8
YEAR TO DATE	2007	3.3	19.3
JULY	2006	3.9	19.7
AUGUST	2006	3.9	19.7
SEPTEMBER	2006	3.6	18.7
OCTOBER	2006	3.6	18.8
NOVEMBER	2006	3.4	19.6
DECEMBER	2006	3.4	20.0
JANUARY	2007	3.3	18.8
FEBRUARY	2007	3.4	18.7
MARCH	2007	3.3	19.5
APRIL	2007	3.4	19.0
MAY	2007	3.2	19.9
JUNE	2007	3.2	19.9

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COMPOSITE INDEX

COMBINATION GAS & ELECTRIC COMPANIES

		DIVIDEND YIELD	PRICE EARNINGS MULTIPLE
YEAR	1997	6.0	13.6
YEAR	1998	4.8	16.7
YEAR	1999	4.7	16.0
YEAR	2000	5.0	16.1
YEAR	2001	4.1	15.3
YEAR	2002	4.9	14.9
YEAR	2003	3.8	15.3
YEAR	2004	3.4	17.1
YEAR	2005	3.3	18.9
YEAR	2006	3.2	18.7
YEAR TO DATE	2007	3.2	19.2
JULY	2006	3.6	19.0
AUGUST	2006	3.6	19.0
SEPTEMBER	2006	3.4	19.0
OCTOBER	2006	3.4	18.9
NOVEMBER	2006	3.3	19.7
DECEMBER	2006	3.2	18.7
JANUARY	2007	3.2	18.8
FEBRUARY	2007	3.3	18.8
MARCH	2007	3.2	19.8
APRIL	2007	3.3	18.6
MAY	2007	3.1	19.8
JUNE	2007	3.1	19.8

DOD-IR-36

[Morin Direct, p. 26, ll. 4-6]

a. Provide any available support from the financial literature for the statement that the CAPM is a "special case" of the APM.

b. When was the CAPM developed?

c. When was the APM developed?

d. Has Dr. Morin ever used the APM in rate case testimony? If so please provide a complete copy of that testimony.

Dr. Morin's Response:

a. The person who developed the Arbitrage Pricing Model (APM), Professor Steve Ross, refers to the one-factor APM equation as follows: "the equation is identical to that of the CAPM."[1] Another advanced graduate corporate finance textbook states in a chapter on the CAPM and APM that "the CAPM may be viewed as special case of the APM when the market rate of return is assumed to be the single relevant factor."[2]

b. The CAPM was developed concurrently by Sharpe, Mossin, and Lintner in 1964-65.

c. The APM was developed by Stephen Ross in 1976. See Ross, S.A. "The Arbitrage Theory of Capital Asset Pricing," *Journal of Economic Theory,* 1976, 13(2): 383-402.

d. No.

[1] Stephen Ross, *et al.*, *Corporate Finance* (6th ed. 2003).
[2] Thomas Copeland, *et al.*, *Financial Theory and Corporate Policy*, 219 (3d ed. 1992)

DOD-IR-37

[Morin Direct, p. 30]

a. Is it true that Dr. Morin used projected Treasury bond yields in his last HECO testimony?

b. Please explain why he did not use projected yields in his current testimony.

Dr. Morin's Response:

a. Yes.

b. Current interest rate projections for this case did not differ materially from current interest rates when Dr. Morin prepared his testimony.

DOD-IR-38

[Morin Direct, pp. 29, 30]

a. What CAPM risk-free rate is recommended by Brealey and Meyers-T-Bonds or T-Bills? Please explain your response.

b. Does Dr. Morin's CAPM methodology conflict with that of Brealey and Meyers? If so, why; if not, why not?

Dr. Morin's Response:

a. Although a preference for long-term rates is clearly indicated in footnote 8 of page 222 of the Brealey, Myers, and Allen text, the authors do not make a specific recommendation as to what specific risk-free proxy to employ to determine the cost of equity with the CAPM in regulatory proceedings. The Brealey, Myers, and Allen corporate finance textbook is meant to be generic and applicable to the world of corporate finance in general rather than be specific to the regulated utility industry. Dr. Morin points out that Professor Myers has testified in many rate cases and for purposes of utility ratemaking, he has relied on long-term rates. Professor Myers and his colleagues in the Brattle Group have filed numerous rate of return expert testimonies throughout North America and have relied on long-term Treasury yields for purposes of employing the CAPM in utility ratemaking.

The important conceptual point is that the horizon of the selected Treasury bond match the horizon of whatever is being valued. When valuing a regulated utility as a going concern with very long-lived assets, the appropriate Treasury bond should be that of a very long-term Treasury bond.

b. No conflict is indicated, as Dr. Morin has relied on long-term rates as proxies for the risk-free rate in applying the CAPM as duly explained on pages 28-30 of Dr. Morin's testimony. In any event, given the relatively flat nature of the yield curve currently, the differences between short- and long-term rates are minor.

DOD-IR-39

[Morin Direct, p. 32, ll. 15-18]

Please provide the details of the calculation of the DCF cost of equity of the aggregate equity market.

<u>Dr. Morin's Response:</u>

See Dr. Morin's testimony pages 34-35 for the details of the market risk premium (MRP) calculations. The dividend yields for each company and Value Line's growth projections came directly from Value Line Investment Analyzer (VLIA) software, October 2006 edition. Value Line does not allow the dissemination of its proprietary data in electronic format for obvious copyright reasons. The Value Line Investment Analyzer software is made commercially available to investors on a paid commercial subscription basis on CD-ROMs updated monthly and/or on-line, and cannot be replicated or disseminated electronically without violating copyright laws. Dr. Morin and/or his staff will be glad to make available for inspection copyright materials that are proprietary at the Company's premises during normal working hours by arrangement upon reasonable prior notice. The formal Value Line copyright notification in the software reads as follows:

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DOD-IR-40

[Morin Direct, p. 34, f. 10]

a. Please provide a complete copy of the article cited.

b. Please explain why reference to the Harris article does not conflict with Dr. Morin's testimony at page 33 regarding the use of long time periods in determining an appropriate Risk Premium.

c. What is the risk premium for utilities found in the Harris study?

Dr. Morin's Response:

a. The requested article was provided in response to DOD/HECO-IR-3-25 filed April 13, 2005 in Docket No. 04-0113.

b. Whenever using historical return risk premium data, Dr. Morin relies on periods long enough to smooth out short-term aberrations, and to encompass several business and interest rate cycles. Over such long periods, surely investor expectations and realizations converge, or else no one would ever invest any money. Over long periods, it is clear that investor expectations are realized; otherwise, no one would ever invest any funds. Consequently, Dr. Morin ignores realized risk premiums measured over short time periods, since they are heavily dependent on short-term market movements. However, whenever using expected return data as opposed to historical return data, as is the case in the Harris-Marston study, this is no longer necessary.

c. See page 14 of the response to DOD/HECO-IR-3-25 filed April 13, 2005 in Docket No. 04-0113. As one would expect, the utility industry ranks with the lowest beta for the period 1983-1998. Of course, as a result of restructuring, deregulation, and the introduction of competition in the revenue stream, there has been a steady escalation in utility betas since 1998 reaching the 0.90 level in 2007.

DOD-IR-41

[Morin Direct, pp. 31-34]

a. Please explain why Dr. Morin elected not to mention either 1) the recent research regarding the market risk premium, which indicates that current MRP expectations are below historical averages or 2) his own published opinion that a reasonable range of market risk premium is from 5% to 8%.

b. Does Dr. Morin's opinion regarding a reasonable range of market risk premium of 5% to 8% comport with that of Brealey and Meyers? If not, please explain why not.

Dr. Morin's Response:

a. Dr. Morin is well aware of the state of research on the market risk premium (MRP). The academic research on the MRP is vast and often contradictory.

Since Dr. Morin's estimate of the MRP of 7.4% is quite consistent with the gist of the literature on the subject, there was no need to reiterate the literature in his testimony.

Chapter 5 of Dr. Morin's book The New Regulatory Finance provides a comprehensive summary of that literature. To highlight some of the more salient passages, Ibbotson's (now Morningstar) *Stocks, Bonds, Bills, and Inflation 2007 Yearbook* finds that a broad market sample of U.S. common stocks outperformed long-term U.S. government bonds by 6.5 percent. The historical MRP over the income component of long-term Treasury bonds rather than over the total return is 7.1 percent. It has been common practice to assume that this historical result provides an adequate basis for the expected MRP.

In their widely-used textbook, Brealey, Myers, and Allen state: "We have no official position on the exact market risk premium, but we believe a range of 6 to 8 percent is reasonable for the United States."[1]

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[1] Brealey, R.,Myers, S., and Allen, P., *Principles of Corporate Finance,* 8th ed. New York: McGraw-Hill, 2006.

Published work by Dimson, Marsh, and Staunton[2] reports returns over the period 1900 to 2000 for twelve countries, representing 90% of today's world market capitalization. They report an average risk premium over long-term bond returns over all countries of 5.6 percent, with the United States at 7.0 percent. The premium was generally higher for the second half century than for the first. For example, the U.S. had an average risk premium over long-term bonds of 5 percent in the first half century, compared to 7.5 percent in the second half.

A second approach to estimating the MRP is prospective in nature and consists of applying the DCF model to an aggregate equity index, as Dr. Morin did in his direct testimony.

A prospective study cited in direct testimony and published in *Financial Management* by Harris, Marston, Mishra, and O'Brien ("HMMO") provides estimates of the ex ante expected returns for S&P 500 companies over the period 1983-1998.[3] From that study, the average MRP estimate for the overall period is 7.2 percent.

In terms of the most recent research on the issue, in the latest edition of Ibbotson Associates' (now Morningstar) widely-used Valuation Yearbook, 2007 edition, Ibbotson and Chen have updated their study of the prospective MRP and conclude:

> *"Contrary to several recent studies on equity risk premium that declare the forward-looking equity risk premium to be close to zero, or even negative, Ibbotson and Chen have found the long-term supply of equity risk premium to be only slightly lower than the straight historical estimate."*

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[2] Dimson, Elroy, Paul Marsh and Mike Staunton (2000) "Risk and Return in the 20th and 21st centuries." *Business Strategy Review* 11(2): 1-18.

[3] Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, King. J., "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," *Financial Management*, Autumn 2003, pp. 51-66.

In other words, prospective estimates of the MRP are virtually the same as the historical MRP.

b. Dr. Morin's MRP estimate of 7.4% is certainly consistent with the aforementioned 6%-8% MRP range espoused by Brealey, Myers, and Allen. Dr. Morin notes that the same authors rely on a MRP of 8% on their page 222 example and 7% in the Table 8.2 CAPM illustration.

DOD-IR-42

[Morin Direct, pp. 37, 38]

a. Please provide the range of "alphas" that are shown in the research literature and explain why Dr. Morin believes an alpha assumption of 1% to 2% is "low."

b. Please list the research which supports the ECAPM which uses T-Bonds and adjusted betas.

c. Is Dr. Morin able to quantify the impact on either the accuracy of the CAPM or the value of beta of a) the use of T-Bonds instead of T-Bills or b) the use of raw versus adjusted betas? If not, please explain why not.

Dr. Morin's Response:

a. See the table on page 7 of HECO-1808, Appendix A in Dr. Morin's testimony. An alpha range of 1%-2% is low relative to the findings of the empirical literature reported on the table.

b. Most of the empirical studies on the validity of the CAPM utilize raw betas rather than Value Line adjusted betas because the latter were not available over most of the time periods covered in these studies. A study of the relationship between return and adjusted beta is reported on Table 6-7 in Ibbotson Associates Valuation Yearbook 2001. If we exclude the portfolio of very small cap stocks from the relationship due to significant size effects, the relationship between the arithmetic mean return and beta for the remaining portfolios is flatter than predicted and the intercept slightly higher than predicted by the CAPM, as shown on the graph on page 8 of HECO-1808, Appendix A. It is noteworthy that the Ibbotson study relies on adjusted betas as stated on page 95 of the aforementioned study.

See also the 2002 study reported on page 9 of HECO-1808, Appendix A in Dr. Morin's testimony which also provides empirical support for the ECAPM using Value Line adjusted betas.

c. Using an alpha factor of 2% instead of the higher average alpha factor reported on the table on page 12 of HECO-1808, Appendix A in Dr. Morin's testimony reduces the ECAPM estimate by approximately 25 basis points.

DOD-IR-43

[Morin Direct, p. 42]

a. From what point in time are historical allowed returns available from Regulatory Research Associates? Please provide support for your response.

b. Has Dr. Morin used longer-term data (i.e., longer than 1997) for this type of analysis in prior testimony?

<u>Dr. Morin's Response:</u>

a. Allowed return data are made available by Regulatory Research Associates on a quarterly basis since 1987.

b. Yes. See Dr. Morin's testimony in the Potomac Electric Power Company Maryland case filed in 2006 Case No. 9092. The observed inverse relationship between allowed utility returns and interest rates was found to hold over longer periods as well and to be even more significant over the longer period 1987-2006 for which data were available, with a R^2 of 0.83 and a t-value of 9.5.

DOD-IR-44

[Morin Direct, p. 46, l. 15, f. 12]

a. Please provide complete copies of each of the articles cited.

b. Is it true that the Brigham paper cited indicates that there was a direct relationship between allowed returns and interest rates prior to 1980?

c. Is Dr. Morin aware of any evidence from the published academic literature that demonstrates that the expected risk premium varies directly with interest rates? If so, please provide complete copies of any such publication.

Dr. Morin's Response:

a. See attached studies on pages 2 to 41 by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992) and Maddox, Pippert and Sullivan (1995).

b. Yes.

c. See studies attached in a. After 1980, unlike observed historical market risk premiums, observed utility allowed returns vary inversely with interest rates.

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Cost of Capital Estimation

The Risk Premium Approach to Measuring a Utility's Cost of Equity

Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson

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■ In the mid-1960s, Myron Gordon and others began applying the theory of finance to help estimate utilities' costs of capital. Previously, the standard approach in cost of equity studies was the "comparable earnings method," which involved selecting a sample of unregulated companies whose investment risk was judged to be comparable to that of the utility in question, calculating the average return on book equity (ROE) of these sample companies, and setting the utility's service rates at a level that would permit the utility to achieve the same ROE as comparable companies. This procedure has now been thoroughly discredited (see Robichek [15]), and it has been replaced by three market-oriented (as opposed to accounting-oriented) approaches: (i) the DCF method, (ii) the bond-yield-plus-risk-premium method, and (iii) the CAPM, which is a specific version of the generalized bond-yield-plus-risk-premium approach.

Our purpose in this paper is to discuss the risk-premium approach, including the market risk premium that is used in the CAPM. First, we critique the various procedures that have been used in the past to estimate risk premiums. Second, we present some data on estimated risk premiums since 1965. Third, we examine the relationship between equity risk premiums and the level of interest rates, because it is important, for purposes of estimating the cost of capital, to know just how stable the relationship between risk premiums and interest rates is over time. If stability exists, then one can estimate the cost of equity at any point in time as a function of interest rates as reported in *The Wall Street Journal*, the *Federal Reserve Bulletin*, or some similar source.[1] Fourth, while we do not discuss the CAPM directly, our analysis does have some important implications for selecting a market risk premium for use in that model. Our focus is on utilities, but the methodology is applicable to the estimation of the cost of

[1]For example, the Federal Energy Regulatory Commission's Staff recently proposed that a risk premium be estimated every two years and that, between estimation dates, the last-determined risk premium be added to the current yield on ten-year Treasury bonds to obtain an estimate of the cost of equity to an average utility (Docket RM 80-36). Subsequently, the FCC made a similar proposal ("Notice of Proposed Rulemaking," August 13, 1984, Docket No. 84-800). Obviously, the validity of such procedures depends on (i) the accuracy of the risk premium estimate and (ii) the stability of the relationship between risk premiums and interest rates. Both proposals are still under review.

equity for any publicly traded firm, and also for non-traded firms for which an appropriate risk class can be assessed, including divisions of publicly traded corporations.[2]

Alternative Procedures for Estimating Risk Premiums

In a review of both rate cases and the academic literature, we have identified three basic methods for estimating equity risk premiums: (i) the *ex post*, or historic, yield spread method; (ii) the survey method; and (iii) an *ex ante* yield spread method based on DCF analysis.[3] In this section, we briefly review these three methods.

Historic Risk Premiums

A number of researchers, most notably Ibbotson and Sinquefield [12], have calculated historic holding period returns on different securities and then estimated risk premiums as follows:

$$\text{Historic Risk Premium} = \begin{pmatrix} \text{Average of the} \\ \text{annual returns on} \\ \text{a stock index for} \\ \text{a particular} \\ \text{past period} \end{pmatrix} - \begin{pmatrix} \text{Average of the} \\ \text{annual returns on} \\ \text{a bond index for} \\ \text{the same} \\ \text{past period} \end{pmatrix}. \quad (1)$$

Ibbotson and Sinquefield (I&S) calculated both arithmetic and geometric average returns, but most of their risk-premium discussion was in terms of the geometric averages. Also, they used both corporate and Treasury bond indices, as well as a T-bill index, and they analyzed all possible holding periods since 1926. The I&S study has been employed in numerous rate cases in two ways: (i) directly, where the I&S historic risk premium is added to a company's bond yield to obtain an estimate of its cost of equity, and (ii) indirectly, when I&S data are used to estimate the market risk premium in CAPM studies.

There are both conceptual and measurement problems with using I&S data for purposes of estimating the cost of capital. Conceptually, there is no compelling reason to think that investors expect the same relative returns that were earned in the past. Indeed evidence presented in the following sections indicate that relative expected returns should, and do, vary significantly over time. Empirically, the measured historic premium is sensitive both to the choice of estimation horizon and to the end points. These choices are essentially arbitrary, yet they can result in significant differences in the final outcome. These measurement problems are common to most forecasts based on time series data.

The Survey Approach

One obvious way to estimate equity risk premium is to poll investors. Charles Benore [1], the senior utility analyst for Paine Webber Mitchell Hutchins, a leading institutional brokerage house, conducts such a survey of major institutional investors annually. His 1983 results are reported in Exhibit 1.

Exhibit 1. Results of Risk Premium Survey, 1983*

Assuming a double A, long-term utility bond currently yields 12½%, the common stock for the same company would be fairly priced relative to the bond if its expected return was as follows:

Total Return	Indicated Risk Premium (basis points)	Percent of Respondents
over 20½%	over 800	
20½%	800	
19½%	700	
18½%	600	10%
17½%	500	8%
16½%	400	29%
15½%	300	35%
14½%	200	16%
13½%	100	0%
under 13½%	under 100	1%
Weighted average	358	100%

*Benore's questionnaire included the first two columns, while his column provided a space for the respondents to indicate which premium they thought applied. We summarized Benore's responses in the frequency distribution given in Column 3. Also, in his questionnaire each year, Benore adjusts the double A bond yield and the total return (Column 1) to reflect current market conditions. Both the question above and the responses to it were taken from the survey conducted in April 1983.

[2]The FCC is particularly interested in risk-premium methodologies, because (i) only eighteen of the 1,400 telephone companies it regulates have publicly-traded stock, and hence offer the possibility of DCF analysis, and (ii) most of the publicly-traded telephone companies have both regulated and unregulated assets, so a corporate DCF cost might not be applicable to the regulated units of the companies.

[3]In rate cases, some witnesses also have calculated the differential between the yield to maturity (YTM) of a company's bonds and its concurrent ROE, and then called this differential a risk premium. In general, this procedure is unsound, because the YTM on a bond is a *future expected* return on the bond's *market value*, while the ROE is the *past realized* return on the stock's *book value*. Thus, comparing YTMs and ROEs is like comparing apples and oranges.

Benore's results, as measured by the average risk premiums, have varied over the years as follows:

Year	Average RP (basis points)
1978	491
1979	475
1980	423
1981	349
1982	275
1983	358

The survey approach is conceptually sound in that it attempts to measure investors' expectations regarding risk premiums, and the Benore data also seem to be carefully collected and processed. Therefore, the Benore studies do provide one useful basis for estimating risk premiums. However, as with most survey results, the possibility of biased responses and/or biased sampling always exists. For example, if the responding institutions are owners of utility stocks (and many of them are), and if the respondents think that the survey results might be used in a rate case, then they might bias upward their responses to help utilities obtain higher authorized returns. Also, Benore surveys large institutional investors, whereas a high percentage of utility stocks are owned by individuals rather than institutions, so there is a question as to whether his reported risk premiums are really based on the expectations of the "representative" investor. Finally, from a pragmatic standpoint, there is a question as to how to use the Benore data for utilities that are not rated AA. The Benore premiums can be applied as an add-on to the own-company bond yields of any given utility only if it can be assumed that the premiums are constant across bond rating classes. *A priori*, there is no reason to believe that the premiums will be constant.

DCF-Based *Ex Ante* Risk Premiums

In a number of studies, the DCF model has been used to estimate the *ex ante* market risk premium, RP_M. Here, one estimates the average expected future return on equity for a group of stocks, k_M, and then subtracts the concurrent risk-free rate, R_f, as proxied by the yield to maturity on either corporate or Treasury securities:[4]

$$RP_M = k_M - R_F. \quad (2)$$

Conceptually, this procedure is exactly like the I&S approach except that one makes direct estimates of future expected returns on stocks and bonds rather than assuming that investors expect future returns to mirror past returns.

The most difficult task, of course, is to obtain a valid estimate of k_M, the expected rate of return on the market. Several studies have attempted to estimate DCF risk premiums for the utility industry and for other stock market indices. Two of these are summarized next.

Vandell and Kester. In a recently published monograph, Vandell and Kester [18] estimated *ex ante* risk premiums for the period from 1944 to 1978. R_F was measured both by the yield on 90-day T-bills and by the yield on the Standard and Poor's AA Utility Bond Index. They measured k_M as the average expected return on the S&P's 500 Index, with the expected return on individual securities estimated as follows:

$$k_i = \left(\frac{D_1}{P_0}\right)_i + g_i, \quad (3)$$

where,

- D_1 = dividend per share expected over the next twelve months,
- P_0 = current stock price,
- g = estimated long-term constant growth rate, and
- i = the i^{th} stock.

To estimate g_i, Vandell and Kester developed fifteen forecasting models based on both exponential smoothing and trend-line forecasts of earnings and dividends, and they used historic data over several estimating horizons. Vandell and Kester themselves acknowledge that, like the Ibbotson-Sinquefield premiums, their analysis is subject to potential errors associated with trying to estimate expected future growth purely from past data. We shall have more to say about this point later.

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[4] In this analysis, most people have used yields on long-term bonds rather than short-term money market instruments. It is recognized that long-term bonds, even Treasury bonds, are not risk free, so an RP_M based on these debt instruments is smaller than it would be if there were some better proxy to the long-term riskless rate. People have attempted to use the T-bill rate for R_F, but the T-bill rate embodies a different average inflation premium than stocks, and it is subject to random fluctuations caused by monetary policy, international currency flows, and other factors. Thus, many people believe that for cost of capital purposes, R_f should be based on long-term securities.

We did test to see how debt maturities would affect our calculated risk premiums. If a short-term rate such as the 30-day T-bill rate is used, measured risk premiums jump around widely and, so far as we could tell, randomly. The choice of a maturity in the 10- to 30-year range has little effect, as the yield curve is generally fairly flat in that range.

Malkiel. Malkiel [14] estimated equity risk premiums for the Dow Jones Industrials using the DCF model. Recognizing that the constant dividend growth assumption may not be valid, Malkiel used a nonconstant version of the DCF model. Also, rather than rely exclusively on historic data, he based his growth rates on Value Line's five-year earnings growth forecasts plus the assumption that each company's growth rate would, after an initial five-year period, move toward a long-run real national growth rate of four percent. He also used ten-year maturity government bonds as a proxy for the riskless rate. Malkiel reported that he tested the sensitivity of his results against a number of different types of growth rates, but, in his words, "The results are remarkably robust, and the estimated risk premiums are all very similar." Malkiel's is, to the best of our knowledge, the first risk-premium study that uses analysts' forecasts. A discussion of analysts' forecasts follows.

Security Analysts' Growth Forecasts

Ex ante DCF risk premium estimates can be based either on expected growth rates developed from time series data, such as Vandell and Kester used, or on analysts' forecasts, such as Malkiel used. Although there is nothing inherently wrong with time series-based growth rates, an increasing body of evidence suggests that primary reliance should be placed on analysts' growth rates. First, we note that the observed market price of a stock reflects the consensus view of investors regarding its future growth. Second, we know that most large brokerage houses, the larger institutional investors, and many investment advisory organizations employ security analysts who forecast future EPS and DPS, and, to the extent that investors rely on analysts' forecasts, the consensus of analysts' forecasts is embodied in market prices. Third, there have been literally dozens of academic research papers dealing with the accuracy of analysts' forecasts, as well as with the extent to which investors actually use them. For example, Cragg and Malkiel [7] and Brown and Rozeff [5] determined that security analysts' forecasts are more relevant in valuing common stocks and estimating the cost of capital than are forecasts based solely on historic time series. Stanley, Lewellen, and Schlarbaum [16] and Linke [13] investigated the importance of analysts' forecasts and recommendations to the investment decisions of individual and institutional investors. Both studies indicate that investors rely heavily on analysts' reports and incorporate analysts' forecast information in the formation of their expectations about stock returns. A representative listing of other work supporting the use of analysts' ... casts is included in the References section. Thu... dence in the current literature indicates that (i) analysts' forecasts are superior to forecasts based solely on time series data, and (ii) investors do rely on analysts' forecasts. Accordingly, we based our cost of equity, and hence risk premium estimates, on analysts' forecast data.[5]

Risk Premium Estimates

For purposes of estimating the cost of capital using the risk premium approach, it is necessary either tha the risk premiums be time-invariant or that there exists a predictable relationship between risk premiums anc interest rates. If the premiums are constant over time then the constant premium could be added to the pre vailing interest rate. Alternatively, if there exists a stable relationship between risk premiums and interes rates, it could be used to predict the risk premium from the prevailing interest rate.

To test for stability, we obviously need to calculate risk premiums over a fairly long period of time. Prio to 1980, the only consistent set of data we could finc came from Value Line, and, because of the work in volved, we could develop risk premiums only once a year (on January 1). Beginning in 1980, however, we began collecting and analyzing Value Line da... monthly basis, and in 1981 we added monthly esti mates from Merrill Lynch and Salomon Brothers to ou data base. Finally, in mid-1983, we expanded ou analysis to include the IBES data.

Annual Data and Results, 1966–1984

Over the period 1966–1984, we used Value Lin data to estimate risk premiums both for the electri utility industry and for industrial companies, using th companies included in the Dow Jones Industrial an Utility averages as representative of the two group: Value Line makes a five-year growth rate forecast, bu it also gives data from which one can develop a longer term forecast. Since DCF theory calls for a truly long term (infinite horizon) growth rate, we concluded th: it was better to develop and use such a forecast than t

[5]Recently, a new type of service that summarizes the key data from mo analysts' reports has become available. We are aware of two sources such services, the Lynch, Jones, and Ryan's Institutional Brokers Es mate System (IBES) and Zack's Icarus Investment Service. IBES a the Icarus Service gather data from both buy-side and sell-side analy and provide it to subscribers on a monthly basis in both a printed an computer-readable format.

Exhibit 2. Estimated Annual Risk Premiums, Nonconstant (Value Line) Model, 1966–1984

January 1 of the Year Reported	Dow Jones Electrics			Dow Jones Industrials			
	k_{Avg}	R_t	RP	k_{Avg}	R_t	RP	(3) ÷ (6)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1966	8.11%	4.50%	3.61%	9.56%	4.50%	5.06%	0.71
1967	9.00%	4.76%	4.24%	11.57%	4.76%	6.81%	0.62
1968	9.68%	5.59%	4.09%	10.56%	5.59%	4.97%	0.82
1969	9.34%	5.88%	3.46%	10.96%	5.88%	5.08%	0.68
1970	11.04%	6.91%	4.13%	12.22%	6.91%	5.31%	0.78
1971	10.80%	6.28%	4.52%	11.23%	6.28%	4.95%	0.91
1972	10.53%	6.00%	4.53%	11.09%	6.00%	5.09%	0.89
1973	11.37%	5.96%	5.41%	11.47%	5.96%	5.51%	0.98
1974	13.85%	7.29%	6.56%	12.38%	7.29%	5.09%	1.29
1975	16.63%	7.91%	8.72%	14.83%	7.91%	6.92%	1.26
1976	13.97%	8.23%	5.74%	13.32%	8.23%	5.09%	1.13
1977	12.96%	7.30%	5.66%	13.63%	7.30%	6.33%	0.89
1978	13.42%	7.87%	5.55%	14.75%	7.87%	6.88%	0.81
1979	14.92%	8.99%	5.93%	15.50%	8.99%	6.51%	0.91
1980	16.39%	10.18%	6.21%	16.53%	10.18%	6.35%	0.98
1981	17.61%	11.99%	5.62%	17.37%	11.99%	5.38%	1.04
1982	17.70%	14.00%	3.70%	19.30%	14.00%	5.30%	0.70
1983	16.30%	10.66%	5.64%	16.53%	10.66%	5.87%	0.96
1984	16.03%	11.97%	4.06%	15.72%	11.97%	3.75%	1.08

use the five-year prediction.* Therefore, we obtained data as of January 1 from Value Line for each of the Dow Jones companies and then solved for k, the expected rate of return, in the following equation:

$$P_0 = \sum_{t=1}^{n} \frac{D_t}{(1+k)^t} + \left(\frac{D_n(1+g_n)}{k-g_n}\right)\left(\frac{1}{1+k}\right)^n. \qquad (4)$$

Equation (4) is the standard nonconstant growth DCF model: P_0 is the current stock price; D_t represents the forecasted dividends during the nonconstant growth period; n is the years of nonconstant growth; D_n is the first constant growth dividend; and g_n is the constant, long-run growth rate after year n. Value Line provides D_t values for t = 1 and t = 4, and we interpolated to obtain D_2 and D_3. Value Line also gives estimates for ROE and for the retention rate (b) in the terminal year, n, so we can forecast the long-term growth rate as g_n = b(ROE). With all the values in Equation (4) specified except k, we can solve for k, which is the DCF rate of return that would result if the Value Line forecasts were met, and, hence, the DCF rate of return implied in the Value Line forecast.[7]

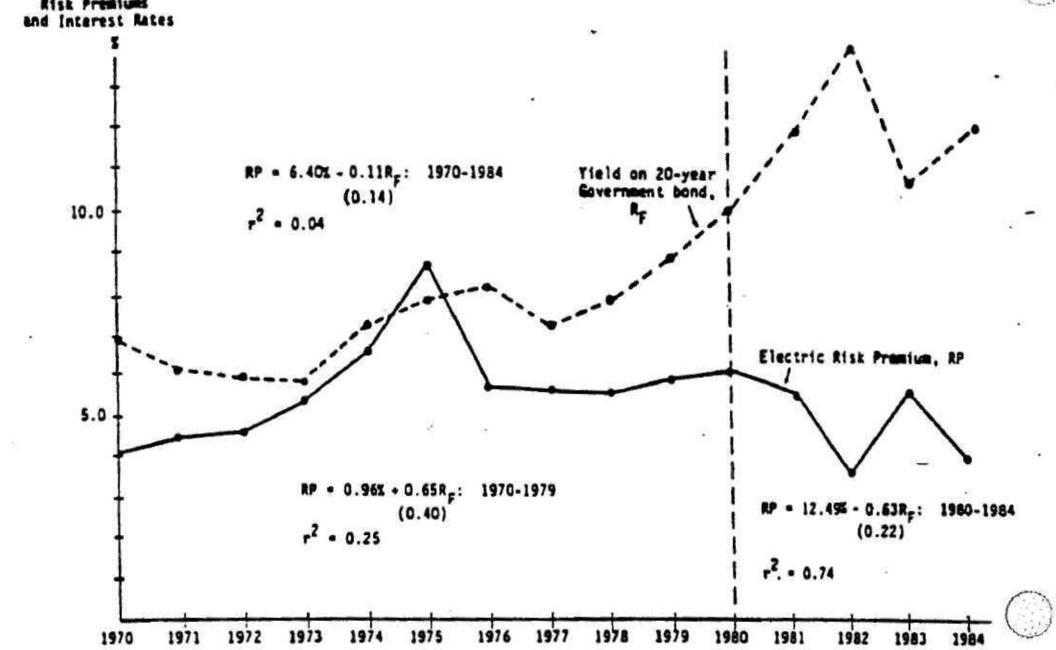
Having estimated a k value for each of the electric and industrial companies, we averaged them (using market-value weights) to obtain a k value for each group, after which we subtracted R_t (taken as the December 31 yield on twenty-year constant maturity Treasury bonds) to obtain the estimated risk premiums shown in Exhibit 2. The premiums for the electrics are plotted in Exhibit 3, along with interest rates. The following points are worthy of note:

1. Risk premiums fluctuate over time. As we shall see in the next section, fluctuations are even wider when measured on a monthly basis.
2. The last column of Exhibit 2 shows that risk premi-

*This is a debatable point. Cragg and Malkiel, as well as many practicing analysts, feel that most investors actually focus on five-year forecasts. Others, however, argue that five-year forecasts are too heavily influenced by base-year conditions and/or other nonpermanent conditions for use in the DCF model. We note (i) that most published forecasts do indeed cover five years, (ii) that such forecasts are typically "normalized" in some fashion to alleviate the base-year problem, and (iii) that for relatively stable companies like those in the Dow Jones averages, it generally does not matter greatly if one uses a normalized five-year or a longer-term forecast, because these companies meet the conditions of the constant-growth DCF model rather well.

[7]Value Line actually makes an explicit price forecast for each stock, and one could use this price, along with the forecasted dividends, to develop an expected rate of return. However, Value Line's forecasted stock price builds in a forecasted *change* in k. Therefore, the forecasted price is inappropriate for use in estimating current values of k.

Exhibit 3. Equity Risk Premiums for Electric Utilities and Yields on 20-Year Government Bonds, 1970–1984*



*Standard errors of the coefficients are shown in parentheses below the coefficients.

ums for the utilities increased relative to those for the industrials from the mid-1960s to the mid-1970s. Subsequently, the perceived riskiness of the two groups has, on average, been about the same.

3. Exhibit 3 shows that, from 1970 through 1979, utility risk premiums tended to have a positive association with interest rates: when interest rates rose, so did risk premiums, and vice versa. However, beginning in 1980, an inverse relationship appeared: rising interest rates led to declining risk premiums. We shall discuss this situation further in the next section.

Monthly Data and Results, 1980–1984

In early 1980, we began calculating risk premiums on a monthly basis. At that time, our only source of analysts' forecasts was Value Line, but beginning in 1981 we also obtained Merrill Lynch and Salomon Brothers' data, and then, in mid-1983, we obtained IBES data. Because our focus was on utilities, we restricted our monthly analysis to that group.

Our 1980–1984 monthly risk premium data, along with Treasury bond yields, are shown in Exhibits 4 and 5 and plotted in Exhibits 6, 7, and 8. Here are some comments on these Exhibits:

1. Risk premiums, like interest rates and stock prices, are volatile. Our data indicate that it would not be appropriate to estimate the cost of equity by adding the current cost of debt to a risk premium that had been estimated in the past. Current risk premiums should be matched with current interest rates.
2. Exhibit 6 confirms the 1980–1984 section of Exhibit 3 in that it shows a strong inverse relationship between interest rates and risk premiums; we shall discuss shortly why this relationship holds.
3. Exhibit 7 shows that while risk premiums based on Value Line, Merrill Lynch, and Salomon Brothers

Exhibit 4. Estimated Monthly Risk Premiums for Electric Utilities Using Analysts' Growth Forecasts, January 1980–June 1984

Beginning of Month	Value Line	Merrill Lynch	Salomon Brothers	Average Premiums	20-Year Treasury Bond Yield, Constant Maturity Series
Jan 1980	6.21%	NA	NA	6.21%	10.18%
Feb 1980	5.77%	NA	NA	5.77%	10.86%
Mar 1980	4.73%	NA	NA	4.73%	12.59%
Apr 1980	5.02%	NA	NA	5.02%	12.71%
May 1980	4.73%	NA	NA	4.73%	11.04%
Jun 1980	5.09%	NA	NA	5.09%	10.37%
Jul 1980	5.41%	NA	NA	5.41%	9.86%
Aug 1980	5.72%	NA	NA	5.72%	10.29%
Sep 1980	5.16%	NA	NA	5.16%	11.41%
Oct 1980	5.62%	NA	NA	5.62%	11.75%
Nov 1980	5.09%	NA	NA	5.09%	12.33%
Dec 1980	5.65%	NA	NA	5.65%	12.37%
Annual Avg	5.35%			5.35%	11.31%
Jan 1981	5.62%	4.76%	5.63%	5.34%	11.99%
Feb 1981	4.82%	4.87%	5.16%	4.95%	12.48%
Mar 1981	4.70%	3.73%	4.97%	4.47%	13.10%
Apr 1981	4.24%	3.23%	4.52%	4.00%	13.11%
May 1981	3.54%	3.24%	4.24%	3.67%	13.51%
Jun 1981	3.57%	4.04%	4.27%	3.96%	13.39%
Jul 1981	3.61%	3.63%	4.16%	3.80%	13.32%
Aug 1981	3.17%	3.05%	3.04%	3.09%	14.23%
Sep 1981	2.11%	2.24%	2.35%	2.23%	14.99%
Oct 1981	2.83%	2.64%	3.24%	2.90%	14.93%
Nov 1981	2.08%	2.49%	3.03%	2.53%	15.27%
Dec 1981	3.72%	3.45%	4.24%	3.80%	13.12%
Annual Avg	3.67%	3.45%	4.07%	3.73%	13.62%
Jan 1982	3.70%	3.37%	4.04%	3.70%	14.00%
Feb 1982	3.05%	3.37%	3.70%	3.37%	14.37%
Mar 1982	3.15%	3.28%	3.75%	3.39%	13.96%
Apr 1982	3.49%	3.61%	4.29%	3.80%	13.69%
May 1982	3.08%	4.25%	3.91%	3.75%	13.47%
Jun 1982	3.16%	4.51%	4.72%	4.13%	13.53%
Jul 1982	2.57%	4.21%	4.21%	3.66%	14.48%
Aug 1982	4.33%	4.83%	5.27%	4.81%	13.69%
Sep 1982	4.08%	5.14%	5.58%	4.93%	12.40%
Oct 1982	5.35%	5.24%	6.34%	5.64%	11.95%
Nov 1982	5.67%	5.95%	6.91%	6.18%	10.97%
Dec 1982	6.31%	6.71%	7.45%	6.82%	10.52%
Annual Avg.	4.00%	4.54%	5.01%	4.52%	13.09%
Jan 1983	5.64%	6.04%	6.81%	6.16%	10.66%
Feb 1983	4.68%	5.99%	6.10%	5.59%	11.01%
Mar 1983	4.99%	6.89%	6.43%	6.10%	10.71%
Apr 1983	4.75%	5.82%	6.31%	5.63%	10.84%
May 1983	4.50%	6.41%	6.24%	5.72%	10.57%
Jun 1983	4.29%	5.21%	6.16%	5.22%	10.90%
Jul 1983	4.78%	5.72%	6.42%	5.64%	11.12%
Aug 1983	3.89%	4.74%	5.41%	4.68%	11.78%
Sep 1983	4.07%	4.90%	5.57%	4.85%	11.71%
Oct 1983	3.79%	4.64%	5.38%	4.60%	11.64%
Nov 1983	2.84%	3.77%	4.46%	3.69%	11.90%
Dec 1983	3.36%	4.27%	5.00%	4.21%	11.83%
Annual Avg.	4.30%	5.37%	5.86%	5.17%	11.22%
Jan 1984	4.06%	5.04%	5.65%	4.92%	11.97%
Feb 1984	4.25%	5.37%	5.96%	5.19%	11.76%
Mar 1984	4.73%	6.05%	6.38%	5.72%	12.12%
Apr 1984	4.78%	5.33%	6.32%	5.48%	12.51%
May 1984	4.36%	5.30%	6.42%	5.36%	12.78%
Jun 1984	3.54%	4.00%	5.63%	4.39%	13.60%

Exhibit 5. Monthly Risk Premiums Based on IBES Data

Beginning of Month	Average of Merrill Lynch, Salomon Brothers, and Value Line Premiums for Dow Jones Electrics	IBES Premiums for Dow Jones Electrics	IBES Premiums for Entire Electric Industry
Aug 1983	4.68%	4.10%	4.16%
Sep 1983	4.85%	4.43%	4.27%
Oct 1983	4.60%	4.31%	3.90%
Nov 1983	3.69%	3.36%	3.36%
Dec 1983	4.21%	3.86%	3.54%
Jan 1984	4.92%	4.68%	4.18%
Feb 1984	5.[illegible]	5.00%	4.36%
Mar 1984	5.[illegible]	5.35%	4.45%
Apr 1984	5.48%	5.33%	4.23%
May 1984	5.36%	5.26%	4.30%
Jun 1984	4.39%	4.47%	3.40%
Average Premiums	4.83%	4.56%	4.01%

Exhibit 6. Utility Risk Premiums and Interest Rates, 1980–1984

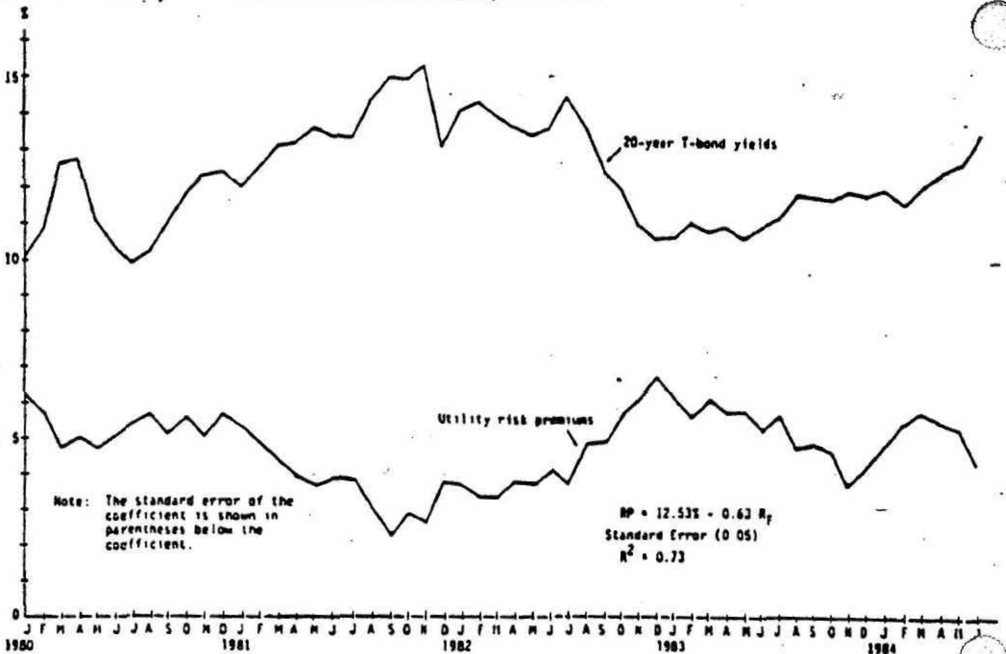


Exhibit 7. Monthly Risk Premiums, Electric Utilities, 1981–1984 (to Date)

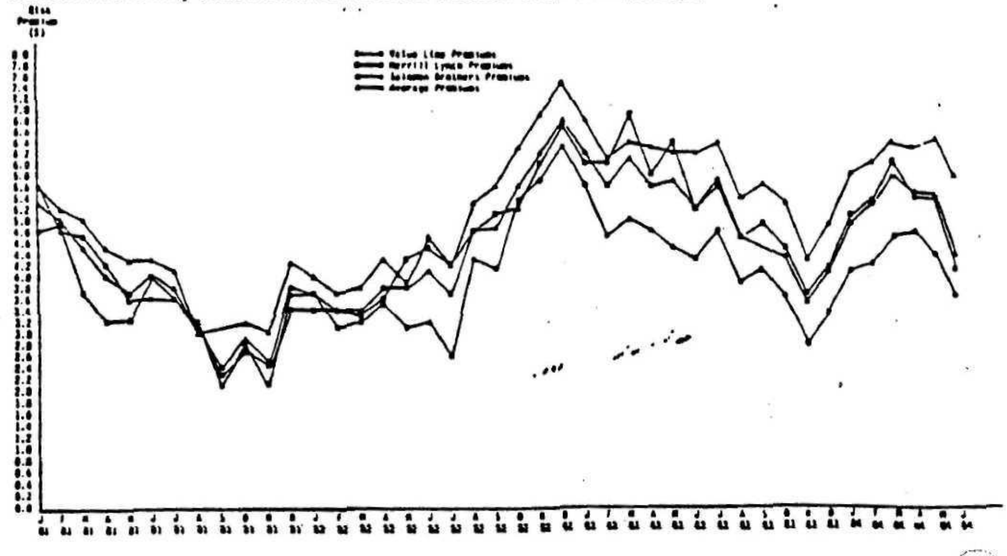
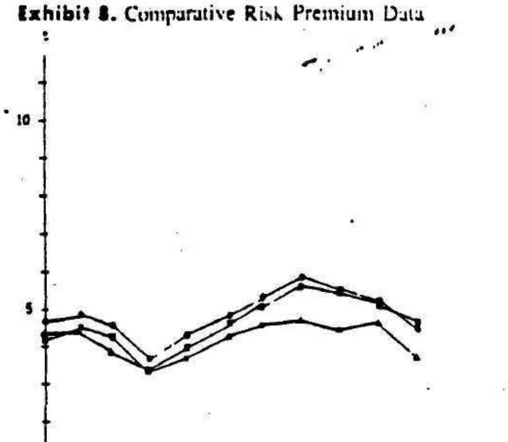


Exhibit 8. Comparative Risk Premium Data



●: Value Line, IR, SB: Dow Jones Electrics
■: IBES: Dow Jones Electrics
▲: IBES: All Electric Utilities

do differ, the differences are not large given the nature of the estimates, and the premiums follow one another closely over time. Since all of the analysts are examining essentially the same data and since utility companies are not competitive with one another, and hence have relatively few secrets, the similarity among the analysts' forecasts is not surprising.

4. The IBES data, presented in Exhibit 5 and plotted in Exhibit 8, contain too few observations to enable us to draw strong conclusions, but (i) the Dow Jones Electrics risk premiums based on our three-analyst data have averaged 27 basis points above premiums based on the larger group of analysts surveyed by IBES and (ii) the premiums on the 11 Dow Jones Electrics have averaged 54 basis points higher than premiums for the entire utility industry followed by IBES. Given the variability in the data, we are, at this point, inclined to attribute these differences to random fluctuations, but as more data become available, it may turn out that the differences are statistically significant. In particular, the 11 electric utilities included in the Dow Jones Utility Index all have large nuclear investments, and this may cause them to be regarded as riskier than the industry average, which includes both nuclear and non-nuclear companies.

Tests of the Reasonableness of the Risk Premium Estimates

So far our claims to the reasonableness of our risk-premium estimates have been based on the reasonableness of our variable measures, particularly the measures of expected dividend growth rates. Essentially, we have argued that since there is strong evidence in the literature in support of analysts' forecasts, risk premiums based on these forecasts are reasonable. In the spirit of positive economics, however, it is also important to demonstrate the reasonableness of our results more directly.

It is theoretically possible to test for the validity of the risk-premium estimates in a CAPM framework. In a cross-sectional estimate of the CAPM equation,

$$(k - R_1)_i = \alpha_0 + \alpha_1\beta_i + u_i, \qquad (5)$$

we would expect

$$\hat{\alpha}_0 = 0 \text{ and } \hat{\alpha}_1 = k_M - R_1 = \text{Market risk premium.}$$

This test, of course, would be a ~~joint test of both~~ the CAPM and the reasonableness of our risk-premium estimates. There is a great deal of evidence that questions the empirical validity of the CAPM, especially when applied to regulated utilities. Under these conditions, it is obvious that no unambiguous conclusion can be drawn regarding the efficacy of the premium estimates from such a test.[a]

A simpler and less ambiguous test is to show that the risk premiums are higher for lower rated firms than for higher rated firms. Using 1984 data, we classified the

[a]We carried out the test on a monthly basis for 1984 and found positive but statistically insignificant coefficients. A typical result (for April 1984) follows:

$$(k - R_1)_i = \underset{(0.91)}{3.1675} + \underset{(1.44)}{1.8031}\ \beta_i.$$

The figures in parentheses are standard errors. Utility risk premiums do increase with betas, but the intercept term is not zero as the CAPM would predict, and α_1 is both less than the predicted value and not statistically significant. Again, the observation that the coefficients do not conform to CAPM predictions could be as much a problem with CAPM specification for utilities as with the risk premium estimates.

A similar test was carried out by Friend, Westerfield, and Granito [9]. They tested the CAPM using expectational (survey) data rather than ex post holding period returns. They actually found their coefficient of β_i to be negative in all their cross-sectional tests.

Exhibit 9. Relationship between Risk Premiums and Bond Ratings, 1984*

Month	Aaa-AA	AA	Aa-A	A	A/BBB	BBB	Below BBB
January†	—	2.61%	3.06%	3.70%	5.07%	4.90%	9.45%
February	2.98%	3.17%	3.36%	4.03%	5.26%	5.14%	7.97%
March	2.34%	3.46%	3.29%	4.06%	5.43%	5.02%	8.28%
April	2.37%	3.03%	3.29%	3.88%	5.29%	4.97%	6.96%
May	2.00%	2.48%	3.42%	3.72%	4.72%	6.64%	8.81%
June	0.72%	2.17%	2.46%	3.16%	3.76%	5.00%	5.58%
Average	2.08%	2.82%	3.15%	3.76%	4.92%	5.28%	7.84%

*The risk premiums are based on IBES data for the electric utilities followed by both IBES and Salomon Brothers. The number of electric utilities followed by both firms varies from month to month. For the period between January and June 1984, the number of electrics followed by both firms ranged from 96 to 99 utilities.
†In January, there were no Aaa/AA companies. Subsequently, four utilities were upgraded to Aaa/AA.

utility industry into risk groups based on bond ratings. For each rating group, we estimated the average risk premium. The results, presented in Exhibit 9, clearly show that the lower the bond rating, the higher the risk premiums. Our premium estimates therefore would appear to pass this simple test of reasonableness.

Risk Premiums and Interest Rates

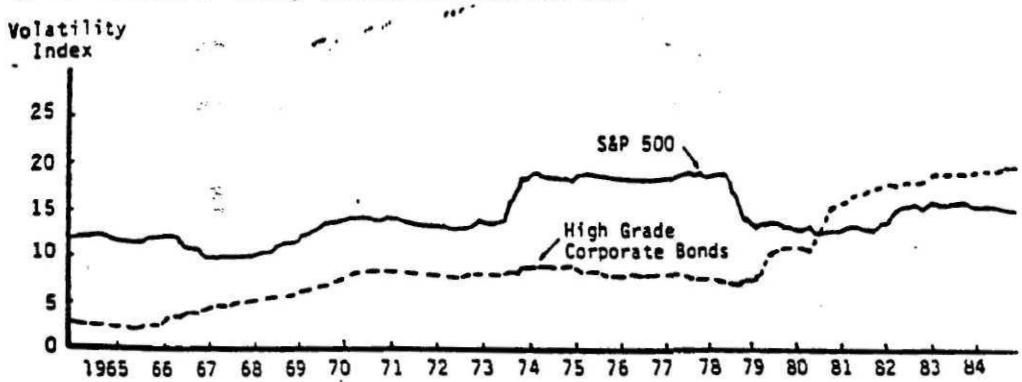
Traditionally, stocks have been regarded as being riskier than bonds because bondholders have a prior claim on earnings and assets. That is, stockholders stand at the end of the line and receive income and/or assets only after the claims of bondholders have been satisfied. However, if interest rates fluctuate, then the holders of long-term bonds can suffer losses (either realized or in an opportunity cost sense) even though they receive all contractually due payments. Therefore, if investors' worries about "interest rate risk" versus "earning power risk" vary over time, then perceived risk differentials between stocks and bonds, and hence risk premiums, will also vary.

Any number of events could occur to cause the perceived riskiness of stocks versus bonds to change, but probably the most pervasive factor, over the 1966–1984 period, is related to inflation. Inflationary expectations are, of course, reflected in interest rates. Therefore, one might expect to find a relationship between risk premiums and interest rates. As we noted in our discussion of Exhibit 3, risk premiums were positively correlated with interest rates from 1966 through 1979, but, beginning in 1980, the relationship turned negative. A possible explanation for this change is given next.

1966–1979 Period. During this period, inflation heated up, fuel prices soared, environmental problems surfaced, and demand for electricity slowed even expensive new generating units were nearing comp tion. These cost increases required offsetting rate hik to maintain profit levels. However, political pressu combined with administrative procedures that were r designed to deal with a volatile economic envirc ment, led to long periods of "regulatory lag" t caused utilities' earned ROEs to decline in absol terms and to fall far below the cost of equit factors combined to cause utility stockholder x rience huge losses: S&P's Electric Index dropped fr a mid-1960s high of 60.90 to a mid-1970s low 20.41, a decrease of 66.5%. Industrial stocks also s fered losses during this period, but, on average, t were only one third as severe as the utilities' loss Similarly, investors in long-term bonds had losses, bond losses were less than half those of utility stoc Note also that, during this period, (i) bond inves were able to reinvest coupons and maturity paym at rising rates, whereas the earned returns on equity not rise, and (ii) utilities were providing a rising sl of their operating income to debtholders versus st holders (interest expense/book value of debt was ing, while net income/common equity was declini This led to a widespread belief that utility commiss would provide enough revenues to keep utilities f going bankrupt (barring a disaster), and hence to tect the bondholders, but that they would not nece ily provide enough revenues either to permit the pected rate of dividend growth to occur or, perh even to allow the dividend to be maintained.

Because of these experiences, investors came t gard inflation as having a more negative effec utility stocks than on bonds. Therefore, whe fea inflation increased, utilities' measured risk a

Exhibit 10. Relative Volatility* of Stocks and Bonds, 1965–1984



*Volatility is measured as the standard deviation of total returns over the last 5 years.
Source: Merrill Lynch, *Quantitative Analysis*, May/June 1984

also increased. A regression over the period 1966–1979, using our Exhibit 2 data, produced this result:

$$RP = 0.30\% + 0.73\,R_t; \quad r^2 = 0.48.$$
$$(0.22)$$

This indicates that a one percentage point increase in the Treasury bond rate produced, on average, a 0.73 percentage point increase in the risk premium, and hence a 1.00 + 0.73 = 1.73 percentage point increase in the cost of equity for utilities.

1980–1984 Period. The situation changed dramatically in 1980 and thereafter. Except for a few companies with nuclear construction problems, the utilities' financial situations stabilized in the early 1980s, and then improved significantly from 1982 to 1984. Both the companies and their regulators were learning to live with inflation: many construction programs were completed; regulatory lags were shortened; and in general the situation was much better for utility equity investors. In the meantime, over most of the 1980–1984 period, interest rates and bond prices fluctuated violently, both in an absolute sense and relative to common stocks. Exhibit 10 shows the volatility of corporate bonds very clearly. Over most of the eighteen-year period, stock returns were much more volatile than returns on bonds. However, that situation changed in October 1979, when the Fed began to focus on the money supply rather than on interest rates.*

In the 1980–1984 period, an increase in inflationary expectations has had a more adverse effect on bonds than on utility stocks. If the expected rate of inflation increases, then interest rates *will increase* and bond prices *will fall*. Thus, uncertainty about inflation translates directly into risk in the bond markets. The effect of inflation on stocks, including utility stocks, is less clear. If inflation increases, then utilities should, in theory, be able to obtain rate increases that would offset increases in operating costs and also compensate for the higher cost of equity. Thus, with "proper" regulation, utility stocks would provide a better hedge against unanticipated inflation than would bonds. This hedge did not work at all well during the 1966–1979 period, because inflation-induced increases in operating and capital costs were not offset by timely rate increases. However, as noted earlier, both the utilities and their regulators seem to have learned to live better with inflation during the 1980s.

Since inflation is today regarded as a major investment risk, and since utility stocks now seem to provide a better hedge against unanticipated inflation than do

*Because the standard deviations in Exhibit 10 are based on the last five years of data, even if bond returns stabilize, as they did beginning in 1982, their reported volatility will remain high for several more years. Thus, Exhibit 10 gives a rough indication of the current relative riskiness of stocks versus bonds, but the measure is by no means precise or necessarily indicative of future expectations.

bonds, the interest rate risk inherent in bonds offsets, to a greater extent than was true earlier, the higher operating risk that is inherent in equities. Therefore, when inflationary fears rise, the perceived riskiness of bonds rises, helping to push up interest rates. However, since investors are today less concerned about inflation's impact on utility stocks than on bonds, the utilities' cost of equity does not rise as much as that of debt, so the observed risk premium tends to fall.

For the 1980–1984 period, we found the following relationship (see Exhibit 6):

$$RP = 12.53\% - 0.63 R_i; \quad r^2 = 0.73.$$
$$(0.05)$$

Thus, a one percentage point increase in the T-bond rate, on average, caused the risk premium to fall by 0.63%, and hence it led to a 1.00 − 0.63 = 0.37 percentage point increase in the cost of equity to an average utility. This contrasts sharply with the pre-1980 period, when a one percentage point increase in interest rates led, on average, to a 1.73 percentage point increase in the cost of equity.

Summary and Implications

We began by reviewing a number of earlier studies. From them, we concluded that, for cost of capital estimation purposes, risk premiums must be based on expectations, not on past realized holding period returns. Next, we noted that expectational risk premiums may be estimated either from surveys, such as the ones Charles Benore has conducted, or by use of DCF techniques. Further, we found that, although growth rates for use in the DCF model can be either developed from time-series data or obtained from security analysts, analysts' growth forecasts are more reflective of investors' views, and, hence, in our opinion are preferable for use in risk-premium studies.

Using analysts' growth rates and the DCF model, we estimated risk premiums over several different periods. From 1966 to 1984, risk premiums for both electric utilities and industrial stocks varied widely from year to year. Also, during the first half of the period, the utilities had smaller risk premiums than the industrials, but after the mid-1970s, the risk premiums for the two groups were, on average, about equal.

The effects of changing interest rates on risk premiums shifted dramatically in 1980, at least for the utilities. From 1965 through 1979, inflation generally had a more severe adverse effect on utility stocks than on bonds, and, as a result, an increase in inflationary expectations, as reflected in interest rates, caused an increase in equity risk premiums. However, in 19 and thereafter, rising inflation and interest rates increased the perceived riskiness of bonds more than that of utility equities, so the relationship between interest rates and utility risk premiums shifted from positive to negative. Earlier, a 1.00 percentage point increase in interest rates had led, on average, to a 1.73% increase in the utilities' cost of equity, but after 1980 a 1.00 percentage point increase in the cost of debt was associated with an increase of only 0.37% in the cost of equity.

Our study also has implications for the use of the CAPM to estimate the cost of equity for utilities. The CAPM studies that we have seen typically use either Ibbotson-Sinquefield or similar historic holding period returns as the basis for estimating the market risk premium. Such usage implicitly assumes (i) that *ex post* returns data can be used to proxy *ex ante* expectations and (ii) that the market risk premium is relatively stable over time. Our analysis suggests that neither of these assumptions is correct; at least for utility stocks, *ex post* returns data do not appear to be reflective of *ex ante* expectations, and risk premiums are volatile, not stable.

Unstable risk premiums also make us question the FERC and FCC proposals to estimate a risk premium for the utilities every two years and then to add the premium to a current Treasury bond rate to determine a utility's cost of equity. Administratively, this proposal would be easy to handle, but risk premiums are simply too volatile to be left in place for two years.

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Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return

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I. Introduction

Shareholder required rates of return play key roles in establishing economic criteria for resource allocation in many corporate and regulatory decisions. Theory dictates that such returns should be forward-looking return requirements that take into account the risk of the specific equity investment.

Estimation of such returns, however, presents numerous and difficult problems. Although theory clearly calls for a forward-looking required return, investigators, lacking a superior alternative, often resort to averages of historical realizations. One primary example is the determination of equity required return as a "least risk" rate plus a risk premium where an equity risk premium is calculated as an average of past differences between equity returns and returns on debt instruments. The historical studies of Ibbotson *et al.* [9] have been used frequently to implement this approach.[1] Use of such historical risk premia assumes that past realizations are a good surrogate for future expectations and that risk premia are roughly constant over time. Additionally, the choice of a time period over which to average data under such a procedure is essentially arbitrary. Carleton and Lakonishok [3] demonstrate empirically some of the problems with such historical premia when they are disaggregated for different time periods or groups of firms.

Recently Brigham, Shome, and Vinson [2] surveyed work on developing *ex ante* equity risk premia with particular emphasis on regulated utilities. They presented their own risk premia estimates, which make use of financial analysts' forecasts as surrogates for investor expectations.

The current paper follows an approach similar to Brigham *et al.* and derives equity required returns and risk premia using publicly available expectational

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[1]Many leading texts in financial management use such historical risk premia to estimate a market return. See for example, Brealey and Myers [1]. Often a market risk premium is adjusted for the observed relative risk of a stock.

data. The estimation makes use of dividend growth models but incorporates expected rather than historical growth rates. A consensus forecast of financial analysts is used as a proxy for investor expectations. While Brigham *et al.* focus on utility securities, this paper also provides estimates of risk premia for a broad market index. Equity risk premia for both the market and for utilities are shown to vary over time with changes in the perceived riskiness of corporate activity relative to U.S. government bonds. In addition, the estimated risk premia at any given time are shown to vary across groups of stocks. The paper also provides results using the dispersion of analysts' forecasts as an *ex ante* proxy for equity risk.

Section II discusses related literature on financial analysts' forecasts (FAF) and the estimation of required returns using such forecasts. In Section III models and data are discussed. Following a comparison of the results to those of earlier studies (including historical risk premia), the estimates are subjected to economic tests of both their time-series and their cross-sectional characteristics in Section V. Finally, conclusions are offered.

II. Background and Literature Review

In finance, it is often convenient to use the notion of a shareholder's required rate of return. Such a rate (k) is the minimum level of expected return necessary to compensate the investor for bearing risks and receiving dollars in the future rather than in the present. In general, k will depend on returns available on alternative investments (*e.g.*, bonds or other equities) and the riskiness of the stock. To isolate the effects of risk it is often useful (both theoretically and empirically) to work in terms of a risk premium (rp), defined as

$$rp = k - i, \tag{1}$$

where i = required return for a zero risk investment. Theoretically, i is a risk free rate, though empirically its proxy (*e.g.*, yield to maturity on a government bond) is only a "least risk" alternative that is itself subject to risk.[2] While models such as the capital asset pricing model offer explicit methods for varying risk premia across securities, they provide little practical advice on establishing some benchmark market risk premium. Other models, such as the dividend growth model (hereafter referred to as the discounted cash flow, or DCF, model), can be used to provide direct estimates of k, and hence implied values of rp, but are silent on how rp ought to vary across firms. In this paper DCF models are used to establish risk premia both for the market and for utility stocks. Since the DCF analysis uses a consensus measure of FAF of earnings as a proxy for investor expectations, a brief review of research on FAF is appropriate.

A. Literature on FAF

Much of the burgeoning literature on properties of FAF is surveyed by Givoly and Lakonishok [8]. Of primary importance for this work is the relationship between FAF and investor expectations that determine stock prices. Such forecast data are readily available. That they are used by investors is evidenced by the commercial viability of services that provide such forecasts and by the results of studies of investors' behavior (Touche, Ross and Company [16], Stanley, Lewellen and Schlarbaum [15]). Moreover, a growing body of knowledge shows that analysts' earnings forecasts are indeed reflected in stock prices. Such studies typically employ a consensus measure of FAF calculated as a simple average[3] of forecasts by individual analysts. Elton, Gruber, and Gultekin [5] show that stock prices react more to changes in analysts' forecasts of earnings than they do to changes in earnings themselves, suggesting the usefulness of FAF as a surrogate for market expectations. In an extensive NBER study using analysts' earnings forecasts, Cragg and Malkiel [4, p. 165] conclude "the expectations formed by Wall Street professionals get quickly and thoroughly impounded into the prices of securities. Implicitly, we have found that the evaluations of companies that analysts make are the sorts of ones on which market valuation is based." Updating Cragg and Malkiel's work, Vander Weide and Carleton [17] recently compare consensus FAF of earnings growth to 41 different historical growth measures.[4] They con-

[2]In this development the effects of tax codes and inflation on required returns are ignored.

[3]Mayshar [14] discusses the problems of explaining equilibrium prices of securities when there is divergence of opinion among investors. One issue is whether it is the expectation of the marginal investor or the average investor that determines security prices. Mayshar shows that, in general given divergence of opinion and trading costs, not all investors trade in all assets and that equilibrium prices and the identity of investors trading in each asset are jointly determined. In this sense, equilibrium prices can be considered as "determined simultaneously by the average and marginal investors."

[4]Both Cragg and Malkiel [4] and Vander Weide and Carleton [17] show that an average measure of analysts' forecasts of growth in earnings is powerful in explaining cross-sectional variation in price earnings ratios of stocks.

clude that "there is overwhelming evidence that the consensus analysts' forecast of future growth is superior to historically-oriented growth measures in predicting the firm's stock price . . . consistent with the hypothesis that investors use analysts' forecasts, rather than historically-oriented growth calculations, in making stock buy and sell decisions." [17, p. 15].

B. Use of FAF to Estimate Equity Required Returns

Given the demonstrated relationship of FAF to equity prices and the direct theoretical appeal of expectational data, it is no surprise that FAF have been used in conjunction with DCF models to estimate equity return requirements. Typically such approaches have estimated an *ex ante* risk premium (rp) calculated as the difference between required return and a least risk rate as shown in Equation (1).

Malkiel [13] estimated such risk premia for the Dow Jones Industrial Index using a nonconstant growth version of the DCF model. Initial years of growth were based on Value Line's five-year earnings growth forecasts with subsequent growth approaching a long-run real national growth rate of 4%. More recently, Brigham, Vinson, and Shome [2] used a two stage DCF growth model to estimate *ex ante* risk premia for electric utilities and the Dow Jones Industrial Index. For the period 1966–1984, they report annual risk premia for both Dow Jones Industrial and Electric Indices using Value Line's forecasts. Beginning in 1980 they report monthly risk premia for electric utilities with the source of FAF varying over time; starting with Value Line, adding Merrill Lynch and Salomon Brothers in 1981 and finally, in mid-1983, adding IBES data. IBES (Institutional Broker's Estimate System) is a collection of analysts' forecasts and is discussed in the next section. The resultant risk premia vary over time. In addition, Brigham *et al.* present evidence that their estimated risk premia vary cross-sectionally with a stock's risk (as proxied by bond rating) and over time with the level of interest rates. FAF also have been used in conjunction with DCF models by a number of expert witnesses in rate of return determination for regulated utilities. Recently, the Federal Communications Commission [6] tentatively endorsed the use of consensus FAF in DCF determinations of required return on equity.[5]

This paper adds to earlier work in a number of important respects. First, while Malkiel and Brigham *et al.* focus on electric utilities or the Dow Jones Industrial Index, this paper estimates risk premia for a broadly defined market index — the Standard and Poor's 500. Thus, the results are directly comparable to historical "market" risk premia typically estimated on a similar sample of stocks. Second, the study uses a large sample of FAF (beginning in 1982 when the necessary data first became available). This provides the ability to use a consensus measure of expectations as would be suggested by financial theory. Third, the results show that the derived risk premia change over time and that these changes are related to proxies for risk, which would be expected to be associated with equity risk premia. Although such changes have been noted by earlier studies (*e.g.*, Brigham *et al.*), there is little work explaining the patterns of change. Finally, the paper shows the usefulness of the dispersion of FAF as a proxy for risk. Such a measure is a direct expectational measure of risk and does not rely on assumptions of risk stability over time as do most operational methods of deriving risk surrogates.

III. Models and Data

A. Model for Estimation

The DCF model states that the current market price is the present value of expected future cash flows from ownership. The simplest and most commonly used version estimates shareholders' required rate of return, k, as the sum of dividend yield and expected growth in dividends, or

$$k = (D_1/P_0) + g, \tag{2}$$

where D_1 = dividend per share expected to be received at time one, P_0 = current price per share (time 0), and g = expected growth rate in dividends per share. The limitations of this model are well known, and it is straightforward to derive expressions for k based on more general specifications of the DCF model.[6] The primary difficulty in using the DCF model is obtaining an estimate of g, since it should reflect market expecta-

[5]In response to the FCC's *Notice of Proposed Rulemaking* [6] to determine authorized rates of return, AT&T used an approach driven by FAF growth estimates from IBES. Also see, for example, W.T. Carleton, *Testimony before the Vermont Public Service Board*, Docket No. 4865 (January 1984) and R.S. Harris, *Testimony filed with the Delaware Public Service Commission*, Docket 84–33 (November 1984). In its *Supplemental Notice* [6], the FCC tentatively endorsed substantial reliance on FAF for use in DCF determination of cost of equity.

[6]As stated, Equation (2) requires expectations of either an infinite horizon of dividend growth at rate g or a finite horizon of dividend growth at rate g and special assumptions about the price of the stock at the end of that horizon. Essentially, the assumption must ensure that the stock price grows at a compound rate of g over the finite horizon.

tions of future performance. Without a ready source for measuring such expectations, application of the DCF model is fraught with difficulties even if the simple version shown in Equation (2) fits the equity investment in question. This paper uses published FAF of long-run growth in earnings as a proxy for g.

B. Data

Many analysts publish forecasts of corporate earnings. Such forecasts are widely disseminated and are the subject of considerable interest both to investors and researchers (see Givoly and Lakonishok [8]). In recent years, this interest has led to a viable market for services that collect and disseminate such FAF. FAF for this research come from IBES (Institutional Broker's Estimate System), which is a product of Lynch, Jones, and Ryan, a major brokerage firm. Data in IBES represent a compilation of earnings per share (EPS) estimates of about 2000 individual analysts from 100 brokerage firms on over 2000 corporations. IBES data are provided to clients in a number of forms, including on-line data bases provided by vendors. The client base, which currently numbers more than 300, includes most large institutional investors such as pension funds, banks, and insurance companies. Representative of industry practice, IBES contains estimates of (i) EPS for the upcoming fiscal year, (ii) EPS for the subsequent year, and (iii) a projected five-year growth rate in EPS. Each item is available at monthly intervals.

IBES collection procedures are designed to obtain timely forecasts made on a consistent basis. IBES requests "normalized" five-year growth rates from analysts. Such normalization is designed to remove short-term distortions that might stem from using an unusually high or low earnings year as a base. These growth and other earnings forecasts are updated when analysts formally change their stated predictions. IBES does, however, verify prior forecasts monthly to make sure that analysts still hold to them. Despite these procedures, there remain potential difficulties in using IBES data to the extent that some analysts fail to normalize growth projections or fail to continually review and revise their earnings estimates. To control for some of these potential difficulties, this analysis uses averages of analysts' forecasts for a wide range of companies over an extended number of months.

In this research, the mean value of individual analyst's forecasts of five-year growth rate in EPS will be used as a proxy for g in the DCF model.[7] The five-year horizon is the longest horizon over which such forecasts are available from IBES and often is the longest horizon used by analysts. One could make alternate assumptions about growth after five years and use a more general version of a DCF model, but unfortunately, there is no source for obtaining market estimates of this expected growth. As a result, the current analysis applies the five-year growth rate as a proxy for g in Equation (2). Given no objective basis for predicting a change in growth (see Footnote 6), this avoids the introduction of *ad hoc* assumptions about future growth. Importantly, however, the approach is applied to portfolios of stocks rather than to individual securities, since future growth patterns may be expected to have drastic changes for some specific securities. Stock prices were obtained from Chase Econometrics and dividend and other firm-specific information from COMPUSTAT. Interest rates (both government and corporate) were gathered from Federal Reserve Bulletins and from Moody's Bond Record. Exhibit 1 describes key variables used in the study. Data collected cover all dividend paying stocks in the Standard and Poor's 500 stock (SP500) index plus approximately

Exhibit 1. Variable Definitions

k	=	equity required rate of return
P_0	=	average daily price per share*
D_1	=	expected dividend per share measured as current indicated annual dividend from COMPUSTAT multiplied by $(1+g)$†
g	=	average financial analysts' forecasts of five-year growth rate in earnings per share (from IBES)
σ_g	=	cross-sectional standard deviation of analysts' forecasts of growth in earnings per share (from IBES)
N_g	=	number of analysts' forecasts of g (from IBES)
i_{20}	=	yield to maturity on 20-year U.S. government obligations. Source: Federal Reserve Bulletin, constant maturity series
i_c	=	yield to maturity on long-term corporate bonds: Moody's average
i_u	=	yield to maturity on long-term public utility bonds: Moody's average
rp	=	equity risk premium calculated as $rp = k - i_{20}$

*In results reported P_0 is the average daily price for a stock from the beginning of the month up to and including the date of publication of monthly IBES data (typically half a month). Almost identical results were found using the average price for the entire month.
†See Footnote 8 at the end of the paper for a discussion of the $(1+g)$ adjustment.

[7]While the model calls for expected growth in dividends, no source of data on such projections is readily available. In addition, in the long run, dividend growth is sustainable only via growth in earnings. As long as payout ratios are not expected to change, the two growth rates will be the same. Vander Weide and Carleton [17] also use the IBES growth rate in earnings per share.

150 additional stocks of regulated companies. Since five-year growth rates were first available from IBES in January 1982, the analysis covers the 36-month period 1982–1984. On average, each company in SP500 had approximately nine individual forecasts of g per month, with some companies having 20 or more forecasts of g. As a result, well over 100,000 FAF (company-months) were employed in the analysis.

IV. Construction of Risk Premia and Required Rates of Return

For each month, a "market" required rate of return was calculated using each dividend paying stock in the SP500 index for which data were available. The DCF model in Equation (2) was applied to each stock and the results weighted by market value of equity to produce the market required return.[8] The return was converted to a risk premium by subtracting i_{20}, the yield to maturity on 20-year U.S. government bonds.[9] The procedure was repeated for the Standard and Poor's Utility Index (SPUT) of 40 stocks. Exhibit 2 reports the results by quarter.

Exhibit 2. Required Rates of Return and Risk Premia

		SP500		SPUT	
	Bond Yield*	Required† Return	Risk‡ Premium	Required† Return	Risk‡ Premium
1982					
Quarter 1	14.27	20.81	6.54	18.83	4.56
Quarter 2	13.74	20.68	6.94	18.51	4.77
Quarter 3	12.94	20.23	7.29	18.55	5.61
Quarter 4	10.72	18.58	7.86	17.20	6.48
Average	12.92	20.08	7.16	18.28	5.36
1983					
Quarter 1	10.87	18.07	7.20	16.71	5.84
Quarter 2	10.80	17.76	6.96	16.52	5.72
Quarter 3	11.79	17.90	6.11	16.39	4.60
Quarter 4	11.90	17.81	5.91	16.00	4.10
Average	11.34	17.88	6.54	16.41	5.07
1984					
Quarter 1	12.09	17.22	5.13	16.48	4.39
Quarter 2	13.21	17.42	4.21	16.99	3.78
Quarter 3	12.83	17.34	4.51	16.62	3.79
Quarter 4	11.78	17.05	5.27	15.18	4.04
Average	12.48	17.26	4.78	16.48	4.00
Average 1982–1984	12.25	18.41	6.16	17.06	4.81

*i_{20} = Yield on U.S. Treasury obligation, 20 year constant maturity.
†Monthly required return (k) calculated as value weighted average. Quarterly values are simple averages of monthly figures.
‡Risk premium calculated as $k - i_{20}$.

The results appear quite plausible. The estimated risk premia are positive, consistent with equity owners demanding a risk premium over and above returns available on debt securities. Also, as would be expected for less risky stocks, the utility risk premia consistently fall below those estimated for stocks in general. Exhibit 2 shows that estimated risk premia change over time, suggesting changes in the market's perception of the incremental risk of investing in equity rather than debt securities. Such changes will be examined in a subsequent section.

For comparative purposes, Exhibit 3 provides results of related studies. The long-run differential return between stocks and long-term government bonds (Panel A) has been about 6.4% per year (on a geometric basis). It is comforting to note that this is very close to the 6.16% average annual risk premia estimated in Exhibit 2. Note, however, that such risk premia appear to change over time. Panels B and C show some of Brigham *et al.*'s risk premium estimates. Unfortunate-

[8]The construction of D_1 is controversial since dividends are paid quarterly and may be expected to change during the year; whereas, Equation (2), as is typical, is being applied to annual data. Both the quarterly payment of dividends (due to investors' reinvestment income before year's end, see Linke, and Zumwalt [11]) and any growth during the year require an upward adjustment of the current annual rate of dividends to construct D_1. If quarterly dividends grew at a constant rate, both factors could be accommodated straightforwardly by applying Equation (2) to quarterly data (with a quarterly growth rate) and then annualizing the estimated quarterly required return. Unfortunately, with lumpy changes in dividends, the precise nature of the adjustment depends, on both an individual company's pattern of growth during the calendar year and an individual company's required return (and hence reinvestment income in that risk class).

In this work, D_1 is calculated as $D_0(1 + g)$. The full g adjustment is a crude approximation to adjust for both growth and reinvestment income. For example, if one expected dividends to have been raised, on average, six months ago, a "½ g" adjustment would allow for growth, the remaining "½ g" would be justified on the basis of reinvestment income. Any precise accounting for both reinvestment income and growth would require tracking each company's dividend change history and making explicit judgments about the quarter of the next change. Since no organized "market" forecasts of such a detailed nature exist, such a procedure is not possible. To get a feel for the magnitudes involved, the average dividend yield (D_1/P_0) and growth (market value weighted 1982–1984) for the SP500 were 5.8% and 12.5%. Comparable figures for the SP utility index were 10.4% and 6.7%. As a result, a "full g" adjustment on average increases the required return by 60–70 basis points (relative to no g adjustment) for both indices.

[9]Brigham, Shome, and Vinson [2] also use this interest rate to create equity risk premia. The results were robust to changes in weighting. For the SP500, equal weighting (rather than value weighting) increased the 1982–1984 risk premium by two basis points while for the SPUT equal weighting resulted in a 21 basis point increase. As a further test, the SP500 stocks were ranked on g and the upper and lower deciles deleted. The resulting risk premium (1982–84 average) was 5.94%. A similar procedure used to rank dividend yield produced an SP500 risk premium of 6.18%.

Exhibit 3. Results of Related Studies: Historical Returns and Estimated Risk Premia

			Geometric	Arithmetic
A. Historical Return Realizations (1926–1980)*				
Common Stocks			9.4%	11.7%
Long-Term Government Bonds			3.0%	3.1%
U.S. Treasury Bills			2.8%	2.8%

	Dow Jones Industrials		Dow Jones Electrics	
	Average	Range	Average	Range
B. DCF risk premia using one analyst†				
1966–1970	5.45	4.97–6.81	3.91	3.46–4.13
1971–1975	5.51	4.95–6.92	5.95	4.52–8.72
1976–1980	6.23	5.09–6.88	5.82	5.55–6.21
1981	5.38		5.62	
1982	5.30		3.70	
1983	5.87		5.64	
1984	3.75		4.06	
Average 1982–1984	4.97		4.47	

	Electric Utilities
C. DCF risk premia using three analysts‡	
1981	3.73
1982	4.52
1983	5.17
1984 (through June)	5.01

*Ibbotson, Sinquefield, and Siegel [9].
†Analyst is Value Line. Data are annual estimates using two-stage growth DCF model. Source: Brigham, Shome, and Vinson [2].
‡Analysts are Value Line, Merrill Lynch and Salomon Brothers. Data are averages of monthly values from Brigham, Shome, and Vinson [2].

ly, their work does not include a broad market index directly comparable to the SP500. Rather, they use the Dow Jones Industrial Index based on 30 large industrial concerns. Though the SPUT includes a broader set of utilities than the electrics covered by Brigham *et al.*, their average risk premium estimates are also in the 4 to 5% range for the early 1980s.

While the estimates in Exhibit 2 are quite plausible, the question still remains as to whether they satisfy economic criteria one would expect of risk premia. In the following section, the estimated risk premia are subjected to a series of tests to see if they vary both cross-sectionally and over time with changes in risk. The tests are ultimately joint tests of the estimates as useful risk premia, the measured proxies for risk and the validity of the economic hypothesis. Nonetheless, if the tests using the risk premia have results conforming to theoretical expectation, the comfort level in using them is increased accordingly.

Exhibit 4. Risk Premia by Moody's Bond Ratings*

Electric Utilities: SIC's 4911 and 4931	Aaa	Aa	A	Baa
Risk Premia				
Risk Premium (Expectational g)	3.60	4.33	4.81	4.90
Risk Premium (Historical g†)	6.10	3.28	3.09	5.24
Financial Data				
Debt Ratio‡	0.46	0.48	0.50	0.51
Beta§	0.58	0.61	0.62	0.61
Variability¶				
Operating Cash Flow	0.009	0.016	0.022	0.059
Equity Cash Flow	0.006	0.013	0.019	0.024
Standard Deviation** of Analysts' Forecasts	1.00	1.26	1.33	1.79

*Moody's ratings as of January 1984 from *Moody's Bond Record*, February 1984. The number of companies by rating is Aaa (2), Aa (22), A (32), Baa (22). Risk premia are averages of monthly values, January 1982–September 1983.
†Historical Growth is past five-year earnings growth, based on 20 quarters of past data. Source: IBES.
‡Debt Ratio = Long-Term Debt ÷ Total Capital, average 1978–1982 from COMPUSTAT.
§Beta from *Value Line*, January 29, 1982.
¶Measure of variability around trend growth: variance of residuals of regressions on quarterly COMPUSTAT data (1978–1982). Regressions are log of variable regressed on time and seasonal dummies.
**This is the average value of the standard deviation around the mean long-term growth forecast. Such standard deviations are reported for each company in each month. Note it is *not* the cross-sectional standard deviation of growth rates among companies.

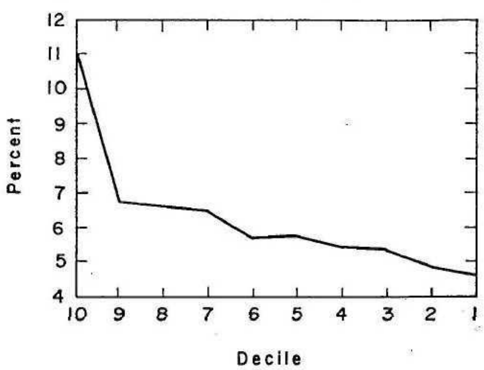
V. Characteristics of Risk Premia

A. Cross-Sectional Tests

Brigham *et al.* show that risk premia (IBES estimates for first half of 1984) for electric utilities are lower the higher the bond rating of the company, confirming the expected tradeoff between risk and return. A similar experiment for electrics, using the current data stretching back to January 1982, confirmed this relationship for a longer time period. Exhibit 4 reports selected results of that analysis. As a contrast, Exhibit 4 also shows the results of using historical growth rates (rather than FAF) in a DCF model. Risk premia derived from historical growth are actually higher for companies with very safe debt, suggesting the clear inferiority of historical to expectational growth rates. With the exception of beta, which is roughly constant across groups, other measures of risk noted in Exhibit 4 confirm the risk differentials associated with bond rating groups.

A further test of the cross-sectional variation in risk premia was performed by dividing the universe of

Exhibit 5. Equity Risk Premia: Deciles Based on Standard Deviation of Financial Analysts Forecasts* (Companies with at least three analysts)



*Risk premia were calculated as equally weighted averages for each decile (10 = highest dispersion) for each of three months: January 1982, December 1982, and September 1983 (approximately 50 companies per decile). These premia were then averaged across deciles. A similar downward pattern was evident in each month.

stocks (industrial plus utility) according to the dispersion of analysts' forecasts, σ_g. This cross-sectional measure of analysts' disagreement should be positively related to the uncertainty of future growth prospects and hence to the riskiness of equity investment. Elsewhere, Malkiel [12] has discussed the rationale and usefulness of such dispersion as an *ex ante* measure of risk. Malkiel argues that σ_g may be a proxy for systematic risk and shows that it bears a closer empirical relationship to expected return than does beta or other risk measures. Most of Malkiel's work is, however, based on data from the 1960s. Exhibit 5 reports risk premia by decile based on σ_g for companies having at least three analysts' forecasts. The three months were chosen as representative. The results show a consistent positive relationship between risk premia and dispersion of analysts' forecasts.

The results in Exhibits 4 and 5 show that the estimated risk premia conform to theoretical relationships between risk and required return that are expected when investors are risk averse. This strengthens the case for using such risk premia, and provides encouragement for further study of their structure.[10]

B. Time Series Tests

A potential benefit of using *ex ante* risk premia is the estimation of changes in risk premia over time. Brigham *et al.* [2] note such changes for utility stocks and relate them to changes in interest rates. They conclude that prior to 1980 utility risk premia increased with the level of interest rates, but that this pattern reversed thereafter, resulting in an inverse correlation between risk premia and interest rates. They explain this turnaround as the outcome of changes in bond markets and adaptation of utilities and their regulators to an inflationary environment. Brigham *et al.* do not, however, analyze changing risk premia for stocks in general. Furthermore, they do not provide direct empirical proxies for changes in equity risks that would explain changes in equity risk premia over time.[11]

C. Changes in Risk Premia

One would expect changes in measured equity risk premia to be related to changes in perceived riskiness. First, with changes in the economy and financial markets, equity investments may be perceived to change in risk. Second, since government bonds are risky investments themselves, their perceived riskiness may change. For example, the large increase in interest rate volatility in the last decade has undoubtedly made fixed income investments more risky holdings than they were in a world of relatively stable rates. Measured equity risk premia (relative to government bonds) could thus be reduced due to increases in perceived riskiness of bonds, even if equities displayed no shifts in risk.

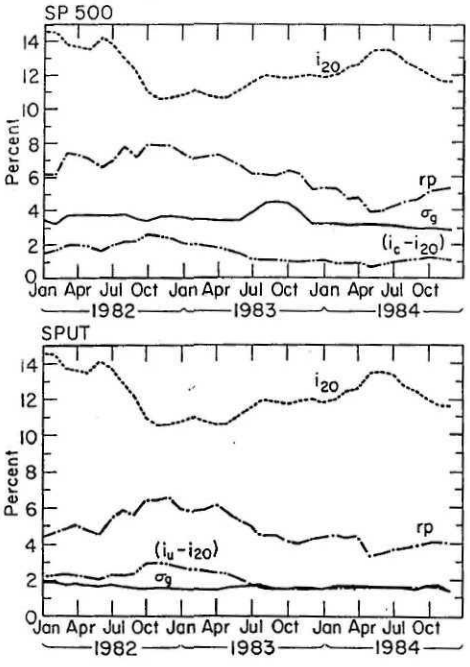
One measure of risk, the standard deviation of FAF, σ_g, was shown previously to be related to cross-sectional differences in risk premia. To test its usefulness as a time series measure of risk, the average value of σ_g was calculated each month for the SP500 index and the SPUT index. The results are graphed in Exhibit 6.[12]

[10]Such *ex ante* required returns offer a useful alternative to *ex post* data typically used in tests of asset pricing models. See Friend, Westerfield, and Granito [7] for a test of the CAPM using survey data rather than *ex post* holding period returns.

[11]In addition, Brigham *et al.* do not report on their treatment of serial correlation in reported regression results, making it more difficult to interpret their findings. As an example, monthly data are used for the 1980–1984 period in a time series regression of a risk premium on the level of interest rates. Similar regressions using data in this paper (1982–1984 monthly data) showed significant positive autocorrelation with Durbin Watson Statistics well below 1.0.

[12]The average values of σ_g are the market value weighted averages of the σ_g for individual stocks. If one looked at a direct estimate of g made by individual analysts for the index, one would expect to find a lower amount of dispersion because some of the differences on individual securities would cancel out. Such data are not available. One would suspect, however, that the calculated average would move up and down in tandem with this unobservable measure of dispersion.

Exhibit 6. Equity Risk Premia, Interest Rates and Risk



Another possible time series proxy for equity risk is the set of yield spreads between corporate and government bonds. As the perceived riskiness of corporate activity increases, the difference between yields on corporate bonds and government bonds should increase. One would expect the sources of increased riskiness to corporate bonds to also increase risks to shareholders.[13] Exhibit 6 graphs two series of yield spreads. The first is the difference between the yield on Moody's corporate average series and the yield on 20-year U.S. Treasury obligations. This series includes debt of both industrial and utility companies and thus would be appropriate as a risk proxy for a broad market index such as the SP500. The second is the spread between the yields on Moody's public utility series and 20-year U.S. Treasury bonds. This series should reflect relative risks of utility stocks as proxied by SPUT.[14]

Exhibit 7 reports results of analyzing the relationship between risk premia, interest rates, and proxies for risk for both the SP500 and SPUT. All regressions are corrected for serial correlation.[15] For stocks in general, Panel A shows that risk premia are negatively related to the level of interest rates — as proxied by i_{20}. Such a negative relationship may result from increases in the perceived riskiness of investment in government debt at high levels of interest rates. A direct measure of uncertainty about investments in government bonds would be necessary to test this hypothesis directly.

The results also show the significant positive relationship between the two proxies for risk and the estimated risk premia. For example, regression 4 of Panel A shows that the equity premium on the SP500 increases with the dispersion of FAF (σ_g) and the yield spread between corporate and government bonds (i_c − i_{20}). Evidently, these two risk measures capture somewhat different dimensions of risk, both of which appear important in explaining risk premia on stocks in general. The simple correlation coefficient between the two risk measures is 0.19 and is insignificantly different from zero. The addition of the yield spread risk proxy also dramatically lowers the magnitude of the coefficient on government bond yields, as can be seen by comparing Equations 1 and 3 of Panel A. Apparently, a large part of the effect of changes in government bond rates on equity risk premia may be explained through the narrowing of the yield spread between corporate and government bonds. This suggests that such increases in government yields may often be associated with a reduction in the *difference* in risk between investment in government bonds and in corporate activity.

Panel B shows that utility risk premia are also inversely related to the level of interest rates as was found by Brigham *et al.* [2]. Unlike the results for stocks in general, however, changes in the dispersion of FAF over time are not significantly related to changes in these utility risk premia. This may be be-

[13]Of course, counterexamples could be constructed but one would expect an overall positive correlation across companies. Additionally, the cross-sectional relationship between bond ratings and equity risk premia reported earlier in the paper supports the link between corporate debt risks and risks on equity.

[14]Note that these two series reflect both changes in the ratings of corporate bonds as well as yield spreads for a given bond rating. The two series proved better in explaining equity risk premia than use of two comparable series for AA-rated debt.

[15]Ordinary least squares regressions showed severe positive autocorrelation in many cases with Durbin Watson Statistics typically below one. Estimation used the Prais-Winsten method. See Johnston [10], pp. 321–325.

Exhibit 7. Changes in Equity Risk Premia Over Time — Entries are Coefficient (t-value)

Regression	Intercept	i_{20}	σ_g	$i_c - i_{20}$	R^2
A. SP500: Dependent Variable is Equity Risk Premium*					
1.	0.140	−0.632			0.43
	(8.15)†	(−4.95)†			
2.	0.118	−0.660	0.754		0.58
	(7.10)†	(−5.93)†	(3.32)†		
3.	0.069	−0.235		1.448	0.57
	(3.44)†	(−1.76)		(4.18)†	
4.	0.030	−0.177	0.855	1.645	0.79
	(2.17)†	(−2.07)†	(4.68)†	(7.63)†	
Regression	Intercept	i_{20}	σ_g	$i_u - i_{20}$	R^2
B. SPUT: Dependent Variable is Equity Risk Premium*					
1.	0.110	−0.510			0.37
	(7.35)†	(−4.41)†			
2.	0.101	−0.543	0.805		0.41
	(6.28)†	(−4.68)†	(1.42)		
3.	0.051	−0.259		1.432	0.80
	(5.54)†	(−4.05)†		(8.87)†	
4.	0.049	−0.287	0.387	1.391	0.80
	(5.15)†	(−3.87)†	(0.75)	(8.14)†	

*All variables are defined in Exhibit 1 and graphed in Exhibit 6. Regressions were estimated for the 36 month period January 1982–December 1984 and were corrected for serial correlation using the Prais-Winsten method. For purposes of this regression variables are expressed in decimal form, *e.g.*, 14% = 0.14.

†Significantly different from zero at 0.05 level using two-tailed test.

cause of lower variability over time in the dispersion of FAF for utility stocks as compared to equities in general. The yield spread between utility and government bonds is significantly positively related to utility equity risk premia. And, as in the case of stocks in general, introduction of this spread substantially reduces the independent effect of interest rate levels on equity risk premia.

Given the short time series (36 months), tests for the stability of the relationships found in Exhibit 7 present difficulties. As a check, the relationships were reestimated dividing the data into two 18-month periods. For stocks in general (SP500), coefficients on σ_g and $(i_c - i_{20})$ were positive in all regressions and significantly so, except in the case of $(i_c - i_{20})$ for the second 18-month period. The coefficient of i_{20} was significantly negative in both periods. This confirms the general findings for the SP500 in Panel A of Exhibit 7. For utility stocks, results for the subperiods also matched the entire period results. The coefficients of $(i_u - i_{20})$ were significantly positive in both subperiods while those of σ_g were insignificantly different from zero. The level of interest rates (i_{20}) had a significant negative effect in both subperiods.

In summary, the estimated risk premia change over time and the patterns of such change are directly related to changes in proxies for the risks of equity investments. Risk premia for both stocks in general and utilities are inversely related to the level of government interest rates but positively related to the bond yield spreads which proxy for the incremental risk of investing in equities rather than government bonds. For stocks in general, risk premia also increase over time with increases in the general level of disagreement about future corporate performance.

VI. Conclusions

Notions of shareholder required rates of return and risk premia are based in theory on investors' expectations about the future. Research has demonstrated the usefulness of financial analysts' forecasts for such expectations. When such forecasts are used to derive equity risk premia, the results are quite encouraging. In addition to meeting the theoretical requirement of using expectational data, the procedure produces estimates of reasonable magnitude that behave as economic theory would predict. Both over time and across stocks, the risk premia vary directly with the perceived riskiness of equity investment.

The approach offers a straightforward and powerful aid in establishing required rates of return either for corporate investment decisions or in the regulatory arena. Since data are readily available on a wide range of equities, an investigator can analyze various proxy groups (*e.g.*, portfolios of utility stocks) appropriate for a particular decision. An additional advantage of the estimated risk premia is that they allow analysis of changes in equity return requirements over time. Tracking such changes is important for managers facing changing economic climates.

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Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts

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■ One of the most widely used concepts in finance is that shareholders require a risk premium over bond yields to bear the additional risks of equity investments. While models such as the two-parameter capital asset pricing model (CAPM) or arbitrage pricing theory offer explicit methods for varying risk premia across securities, the models are invariably linked to some underlying market (or factor-specific) risk premium. Unfortunately, the theoretical models provide limited practical advice on establishing empirical estimates of such a benchmark market risk premium. As a result, the typical advice to practitioners is to estimate the market risk premium based on historical realizations of share and bond returns (see Brealey and Myers [3]).

In this paper, we present estimates of shareholder required rates of return and risk premia which are derived using forward-looking analysts' growth forecasts. We update, through 1991, earlier work which, due to data availability, was restricted to the period 1982-1984 (Harris [12]). Using stronger tests, we also reexamine the efficacy of using such an expectational approach as an alternative to the use of historical averages. Using the S&P 500 as a proxy for the market portfolio, we find an average market risk premium (1982-1991) of 6.47% above yields on long-term U.S. government bonds and 5.13% above yields on corporate bonds. We also find that required returns for individual stocks vary directly with their risk (as proxied by beta) and that the market risk premium varies over time. In particular, the equity market premium over government bond yields is higher in low interest rate environments and when there is a larger spread between corporate and government bond yields. These findings show that, in addition to fitting the theoretical requirement of being forward-looking, the utilization of analysts' forecasts in estimating return requirements provides reasonable empirical results that can be useful in practical applications.

Section I provides background on the estimation of equity required returns and a brief discussion of related

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literature on financial analysts' forecasts (FAF). In Section II, models and data are discussed. Following a comparison of the results to historical risk premia, the estimates are subjected to economic tests of both their time-series and cross-sectional characteristics in Section III. Finally, conclusions are offered in Section IV.

I. Background and Literature Review

In establishing economic criteria for resource allocation, it is often convenient to use the notion of a shareholder's required rate of return. Such a rate (k) is the minimum level of expected return necessary to compensate the investor for bearing risks and receiving dollars in the future rather than in the present. In general, k will depend on returns available on alternative investments (e.g., bonds or other equities) and the riskiness of the stock. To isolate the effects of risk, it is useful to work in terms of a risk premium (rp), defined as

$$rp = k - i, \tag{1}$$

where i = required return for a zero risk investment.[1]

Lacking a superior alternative, investigators often use averages of historical realizations to estimate a benchmark "market" risk premium which then may be adjusted for the relative risk of individual stocks (e.g., using the CAPM or a variant). The historical studies of Ibbotson Associates [13] have been used frequently to implement this approach.[2] This historical approach requires the assumptions that past realizations are a good surrogate for future expectations and, as typically applied, that risk premia are constant over time. Carleton and Lakonishok [5] demonstrate empirically some of the problems with such historical premia when they are disaggregated for different time periods or groups of firms.

As an alternative to historical estimates, the current paper derives estimates of k, and hence, implied values of rp, using publicly available expectational data. This expectational approach employs the dividend growth model (hereafter referred to as the discounted cash flow or DCF model) in which a consensus measure of financial analysts' forecasts (FAF) of earnings is used as a proxy for investor expectations. Earlier works by Malkiel [17], Brigham, Vinson, and Shome [4], and Harris [12] have used FAF in DCF models, and this approach has been employed in regulatory settings (see Harris [12]) and suggested by consultants as an alternative to use of historical data (e.g., Ibbotson Associates [13, pp. 127, 128]). Unfortunately, the published studies use data extending to 1984 at the latest. Our paper draws on this earlier work but extends it through 1991.[3] Our work is closest to that done by Harris [12], who reviews literature showing a strong link between equity prices and FAF and supporting the use of FAF as a proxy for investor expectations. Using data from 1982 to 1984, Harris' results suggest that this expectational approach to estimating equity risk premia is an encouraging alternative to the use of historical averages. He also demonstrates that such risk premia vary both cross-sectionally with the riskiness of individual stocks and over time with financial market conditions.

II. Models and Data

A. Model for Estimation

The simplest and most commonly used version of the DCF model to estimate shareholders' required rate of return, k, is shown in Equation (2):

$$k = \left(\frac{D_1}{P_0}\right) + g, \tag{2}$$

where D_1 = dividend per share expected to be received at time one, P_0 = current price per share (time 0), and g = expected growth rate in dividends per share. The limitations of this model are well known, and it is straightforward to derive expressions for k based on more general specifications of the DCF model.[4] The primary difficulty in using the DCF model is obtaining an estimate of g, since it should reflect market expectations of future perfor-

[1]Theoretically, i is a risk-free rate, though empirically its proxy (e.g., yield to maturity on a government bond) is only a "least risk" alternative that is itself subject to risk. In this development, the effects of tax codes on required returns are ignored.

[2]Many leading texts in financial management use such historical risk premia to estimate a market return. See, for example, Brealey and Myers [3]. Often a market risk premium is adjusted for the observed relative risk of a stock.

[3]See Harris [12] for a discussion of the earlier work and a detailed discussion of the approach employed here.

[4]As stated, Equation (2) requires expectations of either an infinite horizon of dividend growth at a rate g or a finite horizon of dividend growth at rate g and special assumptions about the price of the stock at the end of that horizon. Essentially, the assumption must ensure that the stock price grows at a compound rate of g over the finite horizon. One could alternatively estimate a nonconstant growth model, although the proxies for multistage growth rates are even more difficult to obtain than single stage growth estimates. Marston, Harris, and Crawford [19] examine publicly available data from 1982-1985 and find that plausible measures of risk are more closely related to expected returns derived from a constant growth model than to those derived from multistage growth models. These findings illustrate empirical difficulties in finding empirical proxies for multistage growth models for large samples.

mance. Without a ready source for measuring such expectations, application of the DCF model is fraught with difficulties. This paper uses published FAF of long-run growth in earnings as a proxy for g.

B. Data

FAF for this research come from IBES (Institutional Broker's Estimate System), which is a product of Lynch, Jones, and Ryan, a major brokerage firm.[5] Representative of industry practice, IBES contains estimates of (*i*) EPS for the upcoming fiscal years (up to five separate years), and (*ii*) a five-year growth rate in EPS. Each item is available at monthly intervals.

The mean value of individual analysts' forecasts of five-year growth rate in EPS will be used as a proxy for g in the DCF model.[6] The five-year horizon is the longest horizon over which such forecasts are available from IBES and often is the longest horizon used by analysts. IBES requests "normalized" five-year growth rates from analysts in order to remove short-term distortions that might stem from using an unusually high or low earnings year as a base.

Dividend and other firm-specific information come from COMPUSTAT. Interest rates (both government and corporate) are gathered from Federal Reserve Bulletins and *Moody's Bond Record*. Exhibit 1 describes key variables used in the study. Data collected cover all dividend paying stocks in the Standard & Poor's 500 stock (S&P 500) index, plus approximately 100 additional stocks of regulated companies. Since five-year growth rates are first available from IBES beginning in 1982, the analysis covers the 113-month period from January 1982 to May 1991.

Exhibit 1. Variable Definitions

k	=	Equity required rate of return.
P_0	=	Average daily price per share.
D_1	=	Expected dividend per share measured as current indicated annual dividend from COMPUSTAT multiplied by $(1 + g)$.[a]
g	=	Average financial analysts' forecast of five-year growth rate in earnings per share (from IBES).
i_{lt}	=	Yield to maturity on long-term U.S. government obligations (source: Federal Reserve Bulletin, constant maturity series).
i_c	=	Yield to maturity on long-term corporate bonds: Moody's average.[b]
rp	=	Equity risk premium calculated as $rp = k - i$.
β	=	beta, calculated from CRSP monthly data over 60 months.

Notes:
[a]See footnote 7 for a discussion of the $(1 + g)$ adjustment.
[b]The average corporate bond yield across bond rating categories as reported by Moody's. See *Moody's Bond Survey* for a brief description and the latest published list of bonds included in the bond rating categories.

III. Risk Premia and Required Rates of Return

A. Construction of Risk Premia

For each month, a "market" required rate of return is calculated using each dividend paying stock in the S&P 500 index for which data are available. The DCF model in Equation (2) is applied to each stock and the results weighted by market value of equity to produce the market required return.[7] The return is converted to a risk premium

[5]Harris [12] provides a discussion of IBES data and its limitations. In more recent years, IBES has begun collecting forecasts for each of the next five years. Since this work was completed, the FAF used here have become available from IBES Inc., now a subsidiary of CitiBank.

[6]While the model calls for expected growth in dividends, no source of data on such projections is readily available. In addition, in the long run, dividend growth is sustainable only via growth in earnings. As long as payout ratios are not expected to change, the two growth rates will be the same.

[7]The construction of D_1 is controversial since dividends are paid quarterly and may be expected to change during the year; whereas, Equation (2), as is typical, is being applied to annual data. Both the quarterly payment of dividends (due to investors' reinvestment income before year's end, see Linke and Zumwalt [15]) and any growth during the year require an upward adjustment of the current annual rate of dividends to construct D_1. If quarterly dividends grow at a constant rate, both factors could be accommodated straightforwardly by applying Equation (2) to quarterly data with a quarterly growth rate and then annualizing the estimated quarterly required return. Unfortunately, with lumpy changes in dividends, the precise nature of the adjustment depends on both an individual company's pattern of growth during the calendar year and an individual company's required return (and hence reinvestment income in the risk class).

In this work, D_1 is calculated as $D_0 (1 + g)$. The full g adjustment is a crude approximation to adjust for both growth and reinvestment income. For example, if one expected dividends to have been raised, on average, six months ago, a "1/2 g" adjustment would allow for growth, and the remaining "1/2 g" would be justified on the basis of reinvestment income. Any precise accounting for both reinvestment income and growth would require tracking each company's dividend change history and making explicit judgments about the quarter of the next change. Since no organized "market" forecast of such a detailed nature exists, such a procedure is not possible. To get a feel for the magnitudes involved, during the sample period the dividend yield (D_1/P_0) and growth (market value weighted) for the S&P 500 were typically 4% to 6% and 11% to 13%, respectively. As a result, a "full g" adjustment on average increases the required return by 60 to 70 basis points (relative to no g adjustment).

Exhibit 2. Bond Market Yields, Equity Required Return, and Equity Risk Premium,[a] 1982-1991

	Bond Market Yields[b]		Equity Market Required Return[c]	Equity Risk Premium	
Year	(1) U.S. Gov't	(2) Moody's Corporates	(3) S&P 500	U.S. Gov't (3) - (1)	Moody's Corporates (3) - (2)
1982	12.92	14.94	20.08	7.16	5.14
1983	11.34	12.78	17.89	6.55	5.11
1984	12.48	13.49	17.26	4.78	3.77
1985	10.97	12.05	16.32	5.37	4.28
1986	7.85	9.71	15.09	7.24	5.38
1987	8.58	9.84	14.71	6.13	4.86
1988	8.96	10.18	15.37	6.41	5.19
1989	8.46	9.66	15.06	6.60	5.40
1990	8.61	9.77	15.69	7.08	5.92
1991[d]	8.21	9.41	15.61	7.40	6.20
Average[e]	9.84	11.18	16.31	6.47	5.13

Notes:
[a]Values are averages of monthly figures in percent.
[b]Yields to maturity.
[c]Required return on value weighted S&P 500 index using Equation (1).
[d]Figures for 1991 are through May.
[e]Months weighted equally.

over government bonds by subtracting i_{lt}, the yield to maturity on long-term government bonds. A risk premium over corporate bond yields is also constructed by subtracting i_c, the yield on long-term corporate bonds. Exhibit 2 reports the results by year (averages of monthly data).

The results are quite consistent with the patterns reported earlier (i.e., Harris [12]). The estimated risk premia in Exhibit 2 are positive, consistent with equity owners demanding additional rewards over and above returns on debt securities. The average expectational risk premium (1982 to 1991) over government bonds is 6.47%, only slightly higher than the 6.16% average for 1982 to 1984 reported earlier (Harris [12]). Furthermore, Exhibit 2 shows the estimated risk premia change over time, suggesting changes in the market's perception of the incremental risk of investing in equity rather than debt securities.

For comparison purposes, Exhibit 3 contains historical returns and risk premia. The average expectational risk premium reported in Exhibit 2 falls roughly midway between the arithmetic (7.5%) and geometric (5.7%) long-term differentials between returns on stocks and long-term government bonds. Note, however, that the expectational risk premia appear to change over time. In the following sections, we examine the estimated risk premia to see if they vary cross-sectionally with the risk of individual stocks and over time with financial market conditions.

B. Cross-Sectional Tests

Earlier, Harris [12] conducted crude tests of whether expectational equity risk premia varied with risk proxied by bond ratings and the dispersion of analysts' forecasts and found that required returns increased with higher risk. Here we examine the link between these premia and beta, perhaps the most commonly used measure of risk for equities.[8] In keeping with traditional work in this area, we adopt the methodology introduced by Fama and Macbeth [9] but replace realized returns with expected returns from Equation (2) as the variable to be explained. For this portion of our tests, we restrict our sample to 1982-1987

[8]For other efforts using expectational data in the context of the two-parameter CAPM, see Friend, Westerfield, and Granito [10], Cragg and Malkiel [7], Marston, Crawford, and Harris [19], Marston and Harris [20], and Linke, Kannan, Whitford, and Zumwalt [16]. For a more complete treatment of the subject, see Marston and Harris [20] from which we draw some of these results. Marston and Harris also investigate the role of unsystematic risk and the difference in estimates found when using expected versus realized returns.

Exhibit 3. Average Historical Returns on Bonds, Stocks, Bills, and Inflation in the U.S., 1926-1989

Historical Return Realizations	Geometric	Arithmetic
Common stock	10.3%	12.4%
Long-term government bonds	4.6%	4.9%
Long-term corporate bonds	5.2%	5.5%
Treasury bills	3.6%	3.7%
Inflation rate	3.1%	3.2%

Source: Ibbotson Associates, Inc., *1990 Stocks, Bonds, Bills and Inflation*, 1990 Yearbook.

and in any month include firms that have at least three forecasts of earnings growth to reduce measurement error associated with individual forecasts.[9] This restricted sample still consists of, on average, 399 firms for each of the 72 months (or 28,744 company months).

For a given company in a given month, beta is estimated via the market model (using ordinary least squares) on the prior 60 months of return data taken from CRSP. Beta estimates are updated monthly and are calculated against an equally weighted index of all NYSE securities. For each month, we aggregate firms into 20 portfolios (consisting of approximately 20 securities each). The advantage of grouped data is the reduction in potential measurement error inherent in independent variables at the company level. Portfolios are formed based on a ranking of beta estimated from a prior time period (t = -61 to t = -120). Portfolio expected returns and beta are calculated as the simple averages for the individual securities.

Using these data, we estimate the following model for each of the 72 months:

$$R_p = \alpha_0 + \alpha_1 \beta_p + u_p, \quad p = 1...20, \qquad (3)$$

where:

R_p = Expected return for portfolio p in the given month,

β_p = Portfolio beta, estimated over 60 prior months, and

u_p = A random error term with mean zero.

As a result of estimating regression (3) for each month, 72 estimates of each coefficient (α_0 and α_1) are obtained. Using realized returns as the dependent variable, the traditional approach (e.g., Fama and Macbeth [9]) is to assume that realized returns are a fair game. Given this assumption, the mean of the 72 values of each coefficient is an unbiased estimate of the mean over that same time period if one could have actually used expected returns as the dependent variable. Note that if expected returns are used as the dependent variable the fair-game assumption is not required. Making the additional assumption that the true value of the coefficient is constant over the 72 months, a test of whether the mean coefficient is different from zero is performed using a t-statistic where the denominator is the standard error of the 72 values of the coefficient. This is the technique employed by Fama and Macbeth [9]. If *one assumes the CAPM is correct, the coefficient* α_1 *is an* empirical estimate of the market risk premium, which should be positive.

To test the sensitivity of the results, we also repeat our procedures using individual security returns rather than portfolios. To account, at least in part, for differences in precision of coefficient estimates in different months we also report results in which monthly parameter estimates are weighted inversely by the standard error of the coefficient estimate rather than being weighted equally (following Chan, Hamao, and Lakonishok [6]).

Exhibit 4 shows that there is a significant positive link between expectational required returns and beta. For instance, in Panel A, the mean coefficient of 2.78 on beta is significantly different from zero at better than the 0.001 level (t = 35.31), and each of the 72 monthly coefficients going into this average is positive (as shown by that 100% positive figure). Using individual stock returns, the significant positive link between beta and expected return remains, though it is smaller in magnitude than for portfolios.[10] Comparison of Panels A and B shows that the results are not sensitive to the weighting of monthly coefficients.

While the findings in Exhibit 4 suggest a strong positive link between beta and risk premia (a result often not supported when realized returns are used as a proxy for expectations; e.g., see Tinic and West [22]), the results do not support the predictions of a simple CAPM. In particular, the intercept is higher than a proxy for the risk-free rate over the sample period and the coefficient of beta is well below estimates of a market risk premium obtained from either expectational (Exhibit 2) or historical data (Exhibit

[9]Firms for which the standard deviation of individual FAF exceeded 20 in any month were excluded since we suspect some of these involve errors in data entry. This screen eliminated very few companies in any month. The 1982-1987 period was chosen due to the availability of data on betas.

[10]The smaller coefficients on beta using individual stock portfolio returns are likely due in part to the higher measurement error in measuring individual stock versus portfolio betas.

Exhibit 4. Mean Values of Monthly Parameter Estimates for the Relationship Between Required Returns and Beta for Both Portfolios and Individual Securities (Figures in Parentheses are *t* Values and Percent Positive), 1982-1987

	Intercept	B	Adjusted R^2 [c]	F[c]
Panel A. Equal Weighting[a]				
Portfolio returns	14.06 (54.02, 100)	2.78 (35.31, 100)	0.503	25.4
Security returns	14.77 (58.10, 100)	1.91 (16.50, 99)	0.080	39.0
Panel B. Weighted by Standard Errors[b]				
Portfolio returns	13.86 (215.6, 100)	2.67 (35.80, 100)	0.503	25.4
Security returns	14.63 (398.9, 100)	1.92 (47.3, 99)	0.080	39.0

[a]Equally weighted average of monthly parameters estimated using cross-sectional data for each of the 72 months, January 1982 - December 1987.
[b]In obtaining the reported means, estimates of the monthly intercept and slope coefficients are weighted inversely by the standard error of the estimate from the cross-sectional regression for that month.
[c]Values are averages for the 72 monthly regressions.

3).[11] Nonetheless, the results show that the estimated risk premia conform to the general theoretical relationship between risk and required return that is expected when investors are risk-averse.

C. Time Series Tests — Changes in Market Risk Premia

A potential benefit of using ex ante risk premia is the estimation of changes in market risk premia over time. With changes in the economy and financial markets, equity investments may be perceived to change in risk. For instance, investor sentiment about future business conditions likely affects attitudes about the riskiness of equity investments compared to investments in the bond markets. Moreover, since bonds are risky investments themselves, equity risk premia (relative to bonds) could change due to changes in perceived riskiness of bonds, even if equities displayed no shifts in risk. For example, during the high interest rate period of the early 1980s, the high level of interest rate volatility made fixed income investments more risky holdings than they were in a world of relatively stable rates.

Studying changes in risk premia for utility stocks, Brigham, et al [4] conclude that, prior to 1980, utility risk premia increased with the level of interest rates, but that this pattern reversed thereafter, resulting in an inverse correlation between risk premia and interest rates. Studying risk premia for both utilities and the equity market generally, Harris [12] also reports that risk premia appear to change over time. Specifically, he finds that equity risk premia decreased with the level of government interest rates, increased with the increases in the spread between corporate and government bond yields, and increased with increases in the dispersion of analysts' forecasts. Harris' study is, however, restricted to the 36-month period, 1982 to 1984.

Exhibit 5 reports results of analyzing the relationship between equity risk premia, interest rates, and yield spreads between corporate and government bonds. Following Harris [12], these bond yield spreads are used as a time series proxy for equity risk. As the perceived riskiness of corporate activity increases, the difference between yields on corporate bonds and government bonds should increase. One would expect the sources of increased riskiness to corporate bonds to also increase risks to shareholders. All regressions in Exhibit 5 are corrected for serial correlation.[12]

[11]Estimation difficulties confound precise interpretation of the intercept as the risk-free rate and the coefficient on beta as the market risk premium (see Miller and Scholes [21], and Black, Jensen, and Scholes [2]). The higher than expected intercept and lower than expected slope coefficient on beta are consistent with the prior studies of Black, Jensen, and Scholes [2], and Fama and MacBeth [9] using historical returns. Such results are consistent with Black's [1] zero beta model, although alternative explanations for these findings exist as well (as noted by Black, Jensen, and Scholes [2]).

[12]Ordinary least squares regressions showed severe positive autocorrelation in many cases, with Durbin Watson statistics typically below one. Estimation used the Prais-Winsten method. See Johnston [14, pp. 321-325].

Exhibit 5. Changes in Equity Risk Premia Over Time — Entries are Coefficient (t-value); Dependent Variable is Equity Risk Premium

Time period	Intercept	i_{lt}	$i_c - i_{lt}$	R^2
A. May 1991-1992	0.131 (19.82)	-0.651 (-11.16)		0.53
	0.092 (14.26)	-0.363 (-6.74)	0.666 (5.48)	0.54
B. 1982-1984	0.140 (8.15)	-0.637 (-5.00)		0.43
	0.064 (3.25)	-0.203 (-1.63)	1.549 (4.84)	0.60
C. 1985-1987	0.131 (7.73)	-0.739 (-9.67)		0.74
	0.110 (12.53)	-0.561 (-7.30)	0.317 (1.87)	0.77
D. 1988-1991	0.136 (16.23)	-0.793 (-8.29)		0.68
	0.130 (8.71)	-0.738 (-4.96)	0.098 (0.40)	0.68

Note: All variables are defined in Exhibit 1. Regressions were estimated using monthly data and were corrected for serial correlation using the Prais-Winsten method. For purposes of this regression, variables are expressed in decimal form, e.g., 14% = 0.14.

For the entire sample period, Panel A shows that risk premia are negatively related to the level of interest rates — as proxied by yields on government bonds, i_{lt}. This negative relationship is also true for each of the subperiods displayed in Panels B through D. Such a negative relationship may result from increases in the perceived riskiness of investment in government debt at high levels of interest rates. A direct measure of uncertainty about investments in government bonds would be necessary to test this hypothesis directly.

For the entire 1982 to 1991 period, the addition of the yield spread risk proxy to the regressions dramatically lowers the magnitude of the coefficient on government bond yields, as can be seen by comparing Equations 1 and 2 of Panel A. Furthermore, the coefficient of the yield spread (0.666) is itself significantly positive. This pattern suggests that a reduction in the risk differential between investment in government bonds and in corporate activity is translated into a lower equity market risk premium. Further examination of Panels B through D, however, suggests that the yield spread variable is much more important in explaining changes in equity risk premia in the early portion of the 1980s than in the 1988 to 1991 period.

In summary, market equity risk premia change over time and appear inversely related to the level of government interest rates but positively related to the bond yield spread, which proxies for the incremental risk of investing in equities as opposed to government bonds.

IV. Conclusions

Shareholder required rates of return and risk premia are based on theories about investors' expectations for the future. In practice, however, risk premia are often estimated using averages of historical returns. This paper applies an alternate approach to estimating risk premia that employs publicly available expectational data. At least for the decade studied (1982 to 1991), the resultant average market equity risk premium over government bonds is comparable in magnitude to long-term differences (1926 to 1989) in historical returns between stocks and bonds. There is strong evidence, however, that market risk premia change over time and, as a result, use of a constant historical average risk premium is not likely to mirror changes in investor return requirements. The results also show that the expectational risk premia vary cross-sectionally with the relative risk (beta) of individual stocks.

The approach offers a straightforward and powerful aid in establishing required rates of return either for corporate investment decisions or in the regulatory arena. Since data are readily available on a wide range of equities, an investigator can analyze various proxy groups (e.g., portfolios of utility stocks) appropriate for a particular decision as well as analyze changes in equity return requirements over time.

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An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry

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This study examines the relationship between interest rates and utility equity risk premiums. We found that an inverse relationship exists, with the equity risk premium changing by 37 basis points for each 100 basis-point change in the 30-year Treasury bond yield. The inverse relationship is stable; however, changes in the relative risk of debt and equity securities produce shifts in the level of risk premiums, regardless of the behavior of Treasury bond yields. We also found that the equity risk premiums were consistently positive over the study period, which conforms to the basic risk/return tenet of finance.

■ Several studies published in recent years support an inverse relationship between utility equity risk premiums and interest rates during the first half of the 1980s. Our study provides a more current examination of this relationship. Our findings support the conclusion that equity risk premiums for utility stocks continue to vary inversely with interest rates. Further, the inverse relationship between interest rates and risk premiums appears stable over the sample period; however, market behavior at certain points in the sample period appears to reflect changes in the market's evaluation of the relative risk of Treasury bonds and utility stocks. For instance, significant differences in the level of the risk premium were observed during certain periods, irrespective of the level of interest rates. Considering the dynamic nature of risk premiums, we discuss how the study may be applicable for estimating the cost of equity for utilities.

Section I provides background information and a literature review. Section II describes the research methodology and the data. Section III provides the empirical results. Section IV furnishes an example to illustrate the model's usefulness. Section V furnishes conclusions.

We would like to thank the Editors and an anonymous referee for their helpful comments. The findings, views, and opinions expressed by the authors do not necessarily represent those of their respective employers.

I. Background and Literature Review

The determination of an appropriate cost of equity is a controversial issue in utility rate proceedings. Bond yields provide a readily observable, definitive measure of the market's required return on that investment; however, such a measure is not readily available for stocks. The indefinite life and uncertainty of a firm's future earnings make it necessary to employ theoretical models to arrive at an estimate of the cost of equity. All theoretical models have strengths and weaknesses, and the focus in utility rate proceedings is often on what is wrong with a particular approach rather than what is right. However, the nebulous nature of the true cost of equity provides no definitive way to assess the superiority of one method's results over another's. Consequently, several cost of equity models are typically used to develop a final estimate.

The risk premium method is an alternative approach to the prevalent discounted cash flow (DCF) model in estimating the cost of equity. A fundamental tenet of financial theory is that riskier investments should command a higher expected return than less risky investments. The risk premium may be defined as the difference, or spread, between expected returns on alternative investments. Financial textbooks usually illustrate risk premiums based on a theoretical risk-free rate and the rate for alternative-risk investments along the security market line.

A widespread application of the risk premium method is based on an average of the realized spreads between total returns on equity and debt investments over some historical period. A refinement of this approach is to calculate the average spread between realized equity total returns and bond yields, in order to obtain a forward-looking measure of the required return on debt. Either type of average risk premium is then added to the current cost of debt to obtain a current cost of equity estimate. The assumption implicit in such approaches is that a constant risk premium is embodied in the current cost of equity. A corollary assumption is that the constant risk premium embodied in expected returns is equal to the average of risk premiums measured from realized returns. In actuality, the time period over which past returns are measured can result in significantly different risk premiums. However, many practitioners of this method argue that if the market risk premium is constant, then it is best approximated by realized returns over very long periods of time. These factors underlie the weaknesses of an ex post risk premium approach. Still, this method has cognitive appeal due to the almost tangible dimension added by the measurement of risk premiums from observed returns. There is also great practical appeal to this approach because it is easy to implement by using readily accessible data from sources like Ibbotson Associates (1993), which provide a regularly updated and consistently available compilation of various risk premiums based on holding periods beginning in 1926.

In recent years, an alternative risk premium model has been proposed. It relies on the expected cost of equity, rather than realized returns, as the appropriate basis for measuring risk premiums. Several studies empirically support the hypothesis that risk premiums, as measured by the expected cost of equity, are not constant but, instead, vary inversely with interest rates (Brigham, Shome, and Vinson, 1985; Harris, 1986; Harris and Marston, 1992; and Shome and Smith, 1988). Generally, studies supporting an ex ante risk premium approach are based on data from as early as the mid-1960s through the mid-1980s. The measurement of the ex ante risk premium holds conceptual appeal because it is consistent with the valuation of equity investments based on *expected* returns. However, a practical concern is the reliability of a risk premium measure that must be based upon an estimate of the cost of equity obtained by some other method, such as a DCF model. If problems exist in the formulation of the model used to estimate the cost of equity, those problems are transferred to the risk premium estimate.

An ex ante risk premium study by Brigham et al. (1985) supported the existence of an inverse relationship between interest rates and utility stock risk premiums from 1980 through the first half of 1984. To determine these risk premiums, they employed a two-stage DCF model to obtain monthly cost of equity estimates for utility stocks. Risk premium measures for each month were then derived by deducting an appropriate Treasury bond yield each month. They found that, prior to 1980, the relationship between equity risk premiums and interest rates had been positive. Shome and Smith (1988) obtained similar results, finding an inverse relationship between interest rates and electric utility risk premiums that continued through 1985. Both studies discussed factors that reduced the impact of regulatory lag on utility stocks from the late 1970s into the early 1980s. Both studies concluded that reduced regulatory lag contributed to shifting the relative risk relationship between debt and utility stocks from positive to negative.

These studies were by and large an outgrowth of the market climate of the early 1980s. During that time, the risk of debt instruments rose in both an absolute sense and compared to stocks. This environment led many to conclude that the risk premium had narrowed and some to even argue it was negative.

Shome and Smith (1988) note that while stocks and bonds are both considered to be hedges against anticipated inflation, common stocks are considered to offer a partial hedge against unanticipated inflation. Therefore, during periods of greater inflation uncertainty, Smith and Shome argue that it would seem reasonable that equity risk premiums would decline as interest rates rise (see Gordon and Halpern, 1976). Stated another way, the risk and required return of the less complete hedge (i.e., debt) would increase at a relatively greater rate than the more complete hedge (i.e., equity), thereby reducing the risk premium during periods of higher uncertainty. However, Carleton, Chambers, and Lakonishok (1983) furnish empirical evidence that risk premiums for utility stocks tend to rise with inflation and interest rates if regulatory lag severely hampers earnings and prevents dividends from keeping pace with inflation.

Harris (1986) also finds an inverse relationship between interest rates and ex ante risk premium measures during the early to mid-1980s, based on utility and broader stock market indices. In a more recent study, Harris and Marston (1992) find an inverse relationship between interest rates and ex ante risk premiums for stocks in the S&P 500, based on data from 1982 to 1991. Blanchard (1993) studied real, rather than nominal, risk premiums between 1926 and 1993. Blanchard hypothesized that the persistence of relatively high risk premiums from the late 1930s through the 1940s could have been due to the market's reaction to the high stock market volatility in the late 1920s and early 1930s. Blanchard also suggested that changes in inflation had a more temporal impact on the relative risk of debt and equity. He concluded that there was a declining trend in real risk premiums for the broad market since the 1950s, to a current level of about 2% to 3%. He also concluded that inflation contributed to a transitory increase above the trend in the 1970s and to a transitory decrease below the trend in the 1980s. However, Blanchard finds that real risk premiums were negative throughout much of the 1980s, which leads to the question as to whether the method he used to measure risk premiums is consistent with the basic risk/return tenet of financial theory.

II. Risk Premium Method and Data Sources

In our study, risk premiums for the electric utility industry are based on quarterly cost of equity estimates from 1980 through 1993 for a sample group of 30 electric utilities. Companies in the sample group met the following selection criteria over the review period: 1) principally remained an electric utility company, 2) did not file for Chapter 11 protection, and 3) continuously paid dividends.

Cost of equity estimates were obtained using the constant-growth form of the DCF model:

$$k_e = \frac{D_1}{P} + g \qquad (1)$$

where

k_e = cost of common equity

D_1 = expected annual dividend per share in the coming year

P = current stock price

g = expected growth rate in dividends per share

Brigham et al. (1985) used a two-stage DCF model to estimate the cost of equity and noted that utility companies "meet the conditions of the constant-growth DCF model rather well." The DCF model is also appropriate for utility stocks, perhaps more than for other stocks, because a significant portion of a utility stock's required return is reflected in the dividend yield component.[1] Constant-growth forms of the DCF model were also used by Harris (1986) and Harris and Marston (1992).

[1]Hansen, Kumar, and Shome (1994) found that traditionally high dividend payout ratios in the electric utility industry provided a cost effective means to monitor and manage agency costs related to stockholder-manager and stockholder-regulator conflict.

Data for the DCF model were obtained from *The Value Line Investment Survey.* Part 1, the Summary and Index section of *Value Line*, contains an estimate of the expected dividend-yield (D_1/P) over the next 12 months. The dividend yield for each sample company was based on the *Value Line* yield figure published in the last week of each quarter.

Each company's quarterly growth rate estimate was based on the average of three projected measures: *Value Line*'s projected growth rate in earnings and dividends per share and the projected percentage of common equity retained. The last of the three growth measures is equivalent to the familiar b(r) method of estimating a growth rate. *Value Line*'s growth rates represented a readily available and consistent set of projected growth rates over the study period. Projected growth rates were used in order to be consistent with the ex ante measurement of risk premiums for the study.

The three-month average yield on 30-year Treasury bonds was used as the reference rate. It was subtracted from each company's quarterly cost of equity estimate to derive a risk premium. The risk premiums for each company were then averaged to develop a quarterly risk premium for the electric utility sample.

III. Empirical Results

Figure 1 provides a graph of the observed risk premiums and interest rates. It shows a general inverse trend between the two measures over the period studied. We note that the trend closely resembles the one observed by Brigham et al. (1985). The average interest rate over the study period was 9.77%, and the average risk premium was 3.21%.

To estimate the relationship between electric utility risk premiums and interest rates, we fit a simple linear regression model. Model 1 specifies the regression equation. The risk premium is the dependent variable, and the 30-year Treasury bond yield is the independent variable.

A. Model 1

$$RP_t = \alpha + \beta(TB_t) + \varepsilon \qquad (2)$$

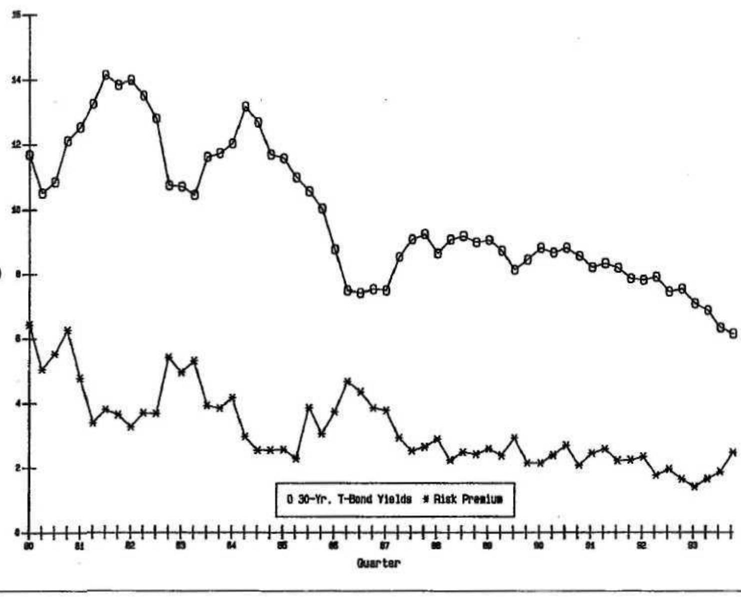
where

RP_t = quarterly average risk premium for all utilities

TB_t = quarterly average 30-year U.S. Treasury bond yield

Initially, we examined our data over the same 1980-1984 time period used by Brigham et al. (1985) and achieved similar results. Expansion of the study period through 1993 produced markedly different results. For example, the adjusted R^2 for Model 1 for the 1980-1993 period was only

Figure 1. Observed Risk Premiums and Treasury Bond Yields Over the Sample Period



0.22, which sharply contrasts with the 0.73 R^2 reported by Brigham et al. (1995) for the 1980-1984 period.

Figure 2 is a graph of all the risk premium data points in the study period for the electric utility industry, with respect to the interest rates at which they were observed. Figure 2 illustrates that there was a divergence in risk premiums that corresponded to interest rates of the same general level during the study period. If a single linear relationship held throughout the observation period, then one would expect very similar risk premium observations at the same general interest rates. This observation led to the hypothesis that perhaps the relative risks of debt and equity were changing over time.

Alternative models were tested to empirically capture the dynamic relationship between risk premiums and interest rates (see Johnston, 1984). We determined that the model specified below was more appropriate than Model 1 for estimating risk premiums over the study period because it would capture this dynamic relationship.

B. Model 2

$$RP_t = \alpha_0 + \alpha_1(D1_t) + \alpha_2(D2_t) + \alpha_3(D3_t) + \alpha_4(D4_t) + \beta(TB_t) + \varepsilon \qquad (3)$$

where

RP_t = quarterly average risk premium for all utilities

$D1_t$ = binary variable equal to 1 for Quarter 2-1984 through Quarter 4-1993, and 0 otherwise

$D2_t$ = binary variable equal to 1 for Quarter 1-1987 through Quarter 4-1993, and 0 otherwise

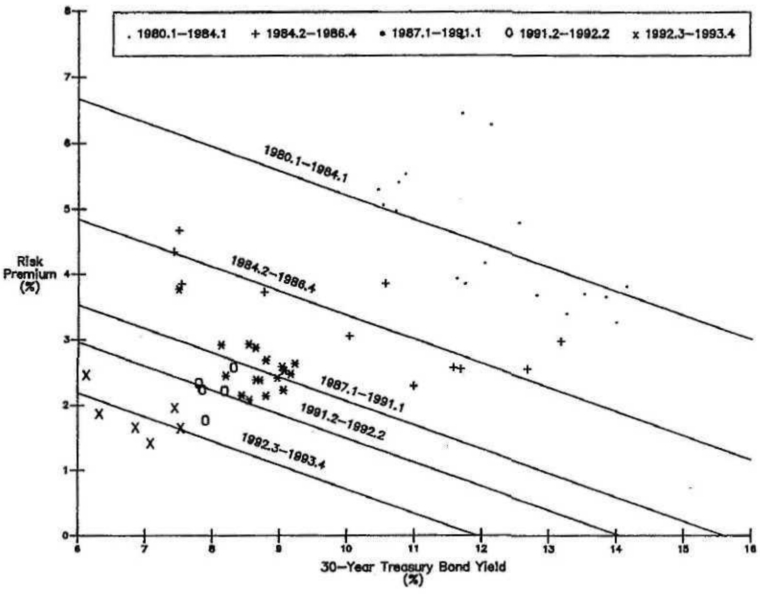
$D3_t$ = binary variable equal to 1 for Quarter 2-1991 through Quarter 4-1993, and 0 otherwise

$D4_t$ = binary variable equal to 1 for Quarter 3-1992 through Quarter 4-1993, and 0 otherwise

TB_t = quarterly average 30-year U.S. Treasury bond yield

The binary variables in Model 2 are included to account for major changes in the relative risks of debt and equity. These changes in relative risk would be reflected as shifts in the level or magnitude of the risk premiums, regardless of the behavior of Treasury bond yields. We did not attempt to determine specific factors that might account for such shifts. Cumulative sum of error tests (see Hall, Johnson, and Lilien, 1990) and break-point Chow tests (see Pindyke and Rubinfeld, 1991) were used to determine the placement

Figure 2. Observed Risk Premiums Plotted Against Treasury Bond Yields



of the binary variables. These tests indicated that significant shifts in the market's evaluation of the relative risk of debt and equity most likely occurred in 1984, 1987, 1991, and 1992.

Table 1 reports the results of fitting Equation (3). These results indicate an inverse relationship between ex ante risk premiums and interest rates over the sample period. A first-order autoregressive correction was made to adjust for the possibility of serial correlation during the sample period (see Johnston, 1984, pp. 321-324). The adjusted R^2 for Model 2 is 0.82. All variables are statistically significantly different from zero at the 0.01 level, except for D3 and D4, which are significant at the 0.05 level. As anticipated, the coefficient estimate of the Treasury bond variable is negative, which indicates the existence of a general inverse relationship between interest rates and risk premiums over the study period.

It is important to note that Model 2 identifies the basic relationship between risk premiums and interest rates, which is defined by the slope coefficient β, as statistically stable over the sample period. Stability of the Treasury bond slope coefficient over the study period was supported by statistical tests that permitted the slope coefficient to change.

C. Interpretation of Empirical Results

The inverse relationship indicated in Table 1 represents approximately 37 basis points for each 100 basis-point change in Treasury bond yields. This result is consistent with the Harris and Marston (1992) study, which found a 36 basis-point inverse relationship between long-term government bond rates and risk premiums for a broader sample of companies for the 1982-1991 period. However, our utility risk premium values are lower than those reported by Harris and Marston for the broader market. One might expect such a difference between the risk premium for utility stocks and the broader market, due to the relatively lower risk of utility stocks.

Harris and Marston found that changes in relative risk, as proxied by a yield spread variable, were important in explaining risk premium changes in subperiods between 1982 and 1991. They also noted, however, that the yield spread variable was more significant in the early 1980s and less significant in the latter 1980s. This phenomenon may be embedded within our intercept dummies, which also exhibited a declining level of magnitude and significance. Interestingly, the break-points for Harris and Marston's

Table 1. Model 2 Regression Results[a]

This table reports the results of fitting Equation (3). The risk premium is the dependent variable.

Variable	Coefficient	Standard Error	t-statistic
Intercept	8.880	0.776	11.444***
TB	-0.368	0.063	-5.878***
D1	-1.828	0.250	-7.318***
D2	-1.309	0.234	-5.598***
D3	-0.569	0.277	-2.051**
D4	-0.773	0.333	-2.320**
Adjusted R^2	0.815	Durbin Waston statistic 1.920	

***Significant at the 0.01 level.
**Significant at the 0.05 level.
[a]Regressions were corrected for the possible existence of serial correlation using the Cochran-Orcutt method.

sub-periods closely approximate the break-points indicated by our tests.

Trends in the overall level of risk premiums provide one of the more intriguing comparisons between our results and those of Harris and Marston. Both studies support an inverse relationship throughout similar study periods. However, the late 1980s and early 1990s produced some of the highest risk premiums in Harris and Marston's study, while the same period produced some of the lowest risk premiums observed in our study. These results may be indicative of higher perceived risk for their broader sample relative to our utility stock sample during this period. Electric utility companies generally have significantly lower reported values for beta than would be reported for a broad market sample of companies. While beta is a somewhat controversial measure of risk, Harris and Marston report a significant positive relationship between beta and risk premiums.

Our results indicate that ex ante risk premiums for electric utility stocks remained inversely related to interest rates over the study period when changes regarding the market's evaluation of relative risk are taken into account. We acknowledge the limitation that our regression model is descriptive of the study period only; however, some measure of robustness would appear to be imparted by the fairly wide range of market climates in our study period.

During the study period, any number of events could have had an impact on the relative risks of debt and equity.[2] In all likelihood, this relationship will continue to be affected by innumerable future events. The projected growth rates for utility dividends and earnings during the early 1980s were viewed by some as too high to be sustainable and therefore not reasonable proxies for the long-run growth rate the DCF model requires. Interestingly, the projected dividend and earnings growth rates for the early 1990s have been viewed by some as too low. Therefore, results of a descriptive model developed from ex ante measures over a period of time can help to provide a reasonableness check concerning an estimate at one point in time.

IV. Usefulness of the Model

In developing cost of equity recommendations, the staff of the Virginia State Corporation Commission (VSCC) presently includes ex ante risk premium methods based on the information presented in this study as well as others. For example, the VSCC staff incorporated an earlier version of the model presented in this paper to formulate a cost of equity recommendation for The Potomac Edison Company in a 1993 rate case. At that time, the model included data from 1980 to 1991, which indicated two shifts in the level of risk premiums, one in the second quarter of 1994 and the other in the first quarter of 1987. The estimated slope coefficient at that time was -0.395, or roughly 40 basis points for each 100 basis-point change in interest rates.

Using the 6.3% average yield on 30-year Treasury bonds from July 1993 to September 1993, the model indicated a risk premium of 3.4%. Combined with the 6.3% interest

[2]Over the study period, the relative risks of debt and equity could have been affected by such factors as changing monetary policy, concern over the growing budget deficit, the savings and loan debacle, the Continental Illinois Bank crisis and other bank industry problems resulting from defaulted loans to developing countries, the leveraged buyout binge of the 1980s, and the 1987 stock market crash, to name a few.

rate, this risk premium produced a 9.7% cost of equity estimate. The VSCC staff also adjusted the average risk premium for the study period based on the model's slope coefficient to obtain a cost of equity estimate for the current level of interest rates. Using this approach, the 3.9% difference between the average interest rate over the study period (10.2%) and the recent 3-month average rate (6.3%) was multiplied by the approximate slope coefficient of 0.4%. The resulting 1.6% was then added to the 3.4% average risk premium for the study period to incorporate the inverse relationship between Treasury yields and utility equity risk premiums. This approach indicated a current risk premium of 5.0%, which indicated a current cost of equity of 11.3% when combined with the 6.3% interest rate. A 10 basis-point flotation cost adjustment was added to both estimates, thus providing cost of equity estimates of 9.8% and 11.4% from the risk premium study. The Potomac Edison Company's requested rate increase reflected a 12.50% return on equity (and increased rates had been in effect on an interim basis subject to refund since September 28, 1993). Ultimately, the VSCC authorized a cost of equity range of 10.4% to 11.4% in its Final Order issued on November 18, 1994.

In addition to providing the basis for a supplemental cost of equity estimate, our risk premium study may be applicable in a more relaxed regulatory framework. For example, in its investigation of alternative regulatory methods for local telephone companies, the VSCC established a number of regulatory options for local telephone companies in Case No. PUE930036. The Earnings Incentive Plan option in that case included the provision for an annually authorized return on equity range that would span 300 basis points and be based on a risk premium approach that recognizes an inverse relationship between risk premiums and interest rates. The risk premium for the bottom of the range in each year would be established as 2.0%, plus 0.5 times the difference between 10.0% and the three-month average yield on 30-year Treasury bonds from September through November of the preceding year. The risk premium for the top of the range would be determined in the same manner, except that the calculation would start with a base level of 5.0%. The resulting risk premiums (subject to the constraint that they cannot be less than zero) are added to the same three-month average yield on 30-year Treasury bonds in the risk premium formula to produce the cost of equity range. The average interest rate and risk premium from a study such as ours could easily be incorporated within a plan like the one developed by the VSCC. While the VSCC's plan did not incorporate a provision for the sharing of earnings, one could be included so that returns above the banded range could be shared.

V. Conclusions

This study furnishes evidence that equity risk premiums are not constant. Our results indicate a statistically significant inverse relationship between interest rates and utility equity risk premiums. Yet, considering that our study covers a recent 14-year period, the hypothesis of a constant ex ante risk premium should also be tested over a longer period. It would also be interesting to test whether the long-term average of ex ante risk premiums converges with the long-term average of ex post risk premiums. ■

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DOD-IR-45

[Morin Direct, p. 53, ll. 13-17]

a. If the projected dividend growth rate is useful in determining the DCF cost of equity for the market in general, why would investors not find it useful in determining the DCF cost of equity for utilities?

b. Please provide the support for the assumption that utilities will lower payout ratios over the next several years.

c. Please provide any available support for the assumption that unregulated firms will not lower dividend payout ratios over the next several years.

Dr. Morin's Response:

a. In contrast to the aggregate equity market as a whole where dividend payouts have not declined, and as explained on pages 52-53 of Dr. Morin's testimony, it is widely expected that utilities will continue to lower their dividend payout ratio over the next several years. In other words, earnings and dividends are not expected to grow at the same rate in the future. Whenever the dividend payout ratio is expected to change, the intermediate growth rate in dividends cannot equal the long-term growth rate, because dividend/earnings growth must adjust to the changing payout ratio. The assumptions of constant perpetual growth and constant payout ratio are clearly not met and the implementation of the standard DCF model is of questionable relevance in this circumstance.

Dividend growth rates are unlikely to provide a meaningful guide to investors' growth expectations for utilities in general because utilities' dividend policies have become increasing conservative as business risks in the industry have intensified steadily. Dividend growth has remained largely stagnant in past years as utilities are increasingly conserving financial resources in order to hedge against rising business risks.

b. According to recent editions of the Value Line Investment Survey, the dividend payout ratio of electric utilities covered by Value Line declined from 75% to 59% from 2002 to 2007. The corresponding Value Line Survey pages prior to this date clearly show the decline from the 80% to the 60% level.

c. Dr. Morin is not aware of any source document forecasting a substantial change in dividend payout policy from their current levels on the part of industrial companies as a whole.

DOD-IR-46

[Morin Direct, p. 62, l. 13]

What is the annual dollar impact on HECO's customers of a 30 basis point increase in the allowed return?

Dr. Morin's Response:

See Company response.

HECO Response:

The estimated impact of a 30 basis point increase in the return on common equity (from 11.25% to 11.55%) on revenue requirements is approximately $4 million. The estimated 2007 test year composite cost of capital with an 11.55% return on common equity (replacing the 11.25% in HECO-1901 filed on December 22, 2006 and with no other revision) is 9.09%. With 9.09% as the rate of return on rate base, the increase in revenues over revenues at current effective rates is 7.4% (versus the 7.1% increase reflected in HECO-2301 filed on December 22, 2006.)

DOD-IR-47

[Morin Direct, p. 62, l. 24 through p. 63, l. 4]

Please list the administrative costs and flotation cost components, including discounts, commissions, corporate expenses, offering spread, and market pressure as a percent of the market price for each of the following sources of equity: conversions of convertible preferred stock, dividend reinvestment plans, employee's savings plans, warrants and stock dividend programs. Also indicate the percentage of each of these sources of equity in HECO's common equity.

Dr. Morin's Response:

All of HECO's common equity capital is obtained from the parent company HEI.

DOD-IR-48

[Morin Direct, p. 65]

Dr. Morin adds 25 basis points to account for the differences in risk between HECO and his electric utility sample group.

a. Please list the bases for business risk comparison between HECO and his sample group, providing, for each category of comparison, the risk measurement for HECO and each company in the sample group.

b. Has Dr. Morin made a comparison between HECO's purchased power risk and the purchased power risk of each company in his sample group? If so, please provide the data used to make that comparison and if not, please explain why not.

<u>Dr. Morin's Response:</u>

a. Dr. Morin relied on two broad samples of electric utilities representative of the industry and then adjusted the results for HECO's degree of risk relative to the two industry groups. The 25 basis points upward return adjustment reflects HECO's relatively small size and its purchase power agreements' debt-equivalent obligations.

b. The table below compiled from Value Line Investment Survey data shows that HEI's percentage of generation from purchased power of 38% far exceeds the average of 21% for traditional vertically-integrated electric utilities in Dr. Morin's sample group of electric utilities. Dr. Morin also notes that the financial risk due to the presence of off-balance sheet liabilities such as purchased power contracts is already reflected in traditional measures of risk for HEI and for Dr. Morin's comparable-risk companies, such as beta and bond rating.

COMPANY	TYPE	% Generation Purch Pwr
Alliant Energy Corporation (NYSE-LNT)	Traditional	20
Ameren Corporation (NYSE-AEE)	Traditional	0
Avista Corporation (NYSE-AVA)	Traditional	0
CH Energy Group, Inc. (NYSE-CHG)	Traditional	96
Cinergy Corp. (NYSE-CIN)	Traditional	0
Consolidated Edison, Inc. (NYSE-ED)	T&D	
Energy East Corporation (NYSE-EAS)	T&D	
Entergy Corporation (NYSE-ETR)	Traditional	0
Exelon Corporation (NYSE-EXC)	Traditional	25
MGE Energy, Inc. (NDQ-MGEE)	Traditional	33
Northeast Utilities (NYSE-NU)	T&D	
NSTAR (NYSE-NST)	T&D	
Pepco Holdings, Inc. (NYSE-POM)	T&D	
PG&E Corporation (NYSE-PCG)	Traditional	67
PNM Resources, Inc. (NYSE-PNM)	Traditional	0
PPL Corporation (NYSE-PPL)	Traditional	
Public Service Enterprise Group (NYSE-PEG)	Traditional	25
TECO Energy, Inc. (NYSE-TE)	Traditional	5
UniSource Energy Corporation (NYSE-UNS)	Traditional	0
Wisconsin Energy Corporation (NYSE-WEC)	Traditional	13
Xcel Energy Inc. (NYSE-XEL)	Traditional	24
AVERAGE		**21**
Hawaiian Energy Ind		**38**

DOD-IR-49

[Morin Direct, p. 67, ll. 10-16]

Please provide copies of the empirical studies referenced.

Dr. Morin's Response:

See attached Section 16-4 of Dr. Morin's latest book The New Regulatory Finance for a review of this literature. Dr. Morin does not archive academic journal articles reaching back some 20 years. The specific journal articles cited in the bibliography are available from the university library.

Chapter 16
Weighted Average Cost of Capital

16.4 Empirical Evidence on Capital Structure

Several researchers have studied the empirical relationship between the cost of capital, capital structure changes, and the value of the firm's securities. Comprehensive and rigorous empirical studies of the relationship between cost of capital and leverage for public utilities, summarized in Patterson (1983), include Modigliani and Miller (1958, 1963), Miller (1977), Brigham and Gordon (1968), Gordon (1974), Robichek, Higgins, and Kinsman (1973), Mehta, Moses, Deschamps, and Walker (1980), Brigham, Shome, and Vinson (1985), and Gapenski (1986). Copeland and Weston (1993) provided a comprehensive summary of the empirical evidence. Although it is not easy in such empirical tests to hold all other relevant factors constant, the evidence partially supports the existence of a tax benefit from leverage and that leverage increases firm value. The evidence also strongly favors a positive relationship between leverage and the cost of equity, which is consistent with the ModiglianiMiller propositions. However, there is still some controversy over the acceptance of the linear formulation in Equations 16-3 and 16-6. Some investigators believe the relationship is curvilinear, others believe it is linear but has a slope less than R - i.

In a study of public utility capital structures, Patterson (1983) concluded that firm value rises with leverage and revenue requirements decline at low levels of leverage, and he confirmed the existence of a cost-minimizing capital structure. Whether this optimal capital structure also minimizes revenue requirements depends on the effectiveness of regulation in passing interest tax savings through to ratepayers. Patterson also found that utilities tend to operate at a debt ratio slightly less than the optimal level, in the interest of flexibility and maintaining borrowing reserves.

The empirical effects of leverage on common equity return are summarized in Brigham, Gapenski, and Aberwald (1987). Tables 16-4 and 16-5 show the results of empirical studies and theoretical studies obtained when the debt ratio increases from 40% to 50%. The studies report that equity costs increase anywhere from a low of 34 to a high of 237 basis points when the debt ratio increases from 40% to 50%. The average increase is 138 basis points from the theoretical studies and 76 basis points from the empirical studies, or a range of 7.6 to 13.8 basis points per one percentage increase in the debt ratio. The more recent studies indicate that the upper end of that range is more indicative of the repercussions on equity costs.

Table 16-4
Effects of Leverage on Common Equity: Empirical Studies

Study	Result
MM (1958)	115 basis points
MM (1963)	62
Miller (1977)	237

Average	**138**

Table 16-5
Effects of Leverage on Common Equity: Theoretical Studies

Study	Result
Brigham and Gordon (1968)	34 basis points
Gordon (1974)	45
Robichek, Higgins, and Kinsman (1973)	75
Mehta, Moses, Deschamps and Walker (1980)	109
Gapenski (1986)	72
Brigham, Gapenski, and Aberwald (1987)	117
Average	**76**

Chapter 18 will show the results of a simulation model designed to investigate empirically the appropriate capital structure of a utility company using current market data and industry trends.

16.5 Conclusions

The benefits and costs of using debt, including taxes, agency costs, and distress costs, were identified and quantified by the various models of capital structure. Both the cost of debt and equity were seen to increase steadily with each increment in financial leverage. Despite the rise of both debt and equity costs with increases in the debt ratio, the WACC reaches a minimum as the weight of low-cost debt in the average increases. Beyond this optimal point, the low-cost and tax advantages of debt are outweighed by the rising distress costs, agency costs, and personal tax disadvantages, and the overall cost of capital increases rapidly at higher debt ratios.

Despite the intuitive and conceptual appeal of this "trade-off" view of the optimal capital structure, it is difficult to quantify precisely the costs/benefits of various debt levels and to establish the optimal level of debt. Moreover, the optimal capital structure shifts over time with changes in capital market conditions and changes in business risk. Chapter 18 will provide a simulation model that circumvents some of these difficulties and determines the optimal bond rating for a utility and the level of debt consistent with that bond rating. Finally, we also know from the signaling framework that utilities should maintain a borrowing reserve, using less debt in normal times so as to build reserve debt capacity when needed.

In the final analysis, finance theory provides limited guidance on what a company's capital structure should be precisely. Capital structure decisions must be determined by managerial judgment and market data in contrast to the exact mathematical formulas resulting from the theories presented in this chapter. Financial theory provides benchmarks and useful data to assist management in capital structure decisions. Capital structure decisions depend critically on each company's own situation and level of business risk as well. The higher the business risk, the lower the debt ratio.

As a practical matter, the effect of capital structure on total weighted average cost of capital is likely to be minor over the range of capital structures usually found in the utility industry. If one subscribes to the majority view that the cost of capital curve is U-shaped, the error committed by assuming a constant debt/equity ratio is not large given the flatness of the curve over the range of capital structures normally employed by utilities. It is reasonably safe to assume that the overall cost of capital is virtually flat across a broad middle range of capital structures for each industry, especially for the utility industry in view of the regulatory treatment of the tax shields from debt financing. This observation is revisited in the comprehensive case study presented in the next chapter. Even if one subscribes to the pure Modigliani-Miller view that cost of capital is a declining function of leverage over a wide range of debt ratios, the magnitude of the error is still likely to be small, especially when compared to the range of reasonableness of cost of capital estimates in regulatory hearings. It is hard not to concur with Myers (1972) that it is fairly safe to estimate a utility's cost of capital on the assumption of a constant debt ratio, unless a major rapid shift in capital structure is contemplated. Similar arguments can be made for a change in dividend policy.

As far as the regulation of capital structure is concerned, the acceptability of a given capital structure is difficult to determine precisely. The debt and equity cost relationships necessary to derive the optimal capital structure are difficult to establish with any degree of precision. Yet, it is the responsibility of regulators to ensure that a utility's capital structure should reflect a proper balance between investors' interests and ratepayers' interests, and should be cost-minimizing. Given the analytical constraints, the acceptability of a utility's capital structure should be governed by a general guideline drawn from the capital structure principles enunciated in this chapter. Such a guideline would ensure that a utility should increase the relative amount of debt it employs to the point where the increased returns required by bond and equity investors exceed the total cost savings derived from substituting low-cost, tax-free debt for high-cost, taxable capital. It is also important that a reasonable safety margin against possible shifts in capital market conditions and investor risk attitudes be allowed.

The optimal capital structure simulation model presented in Chapter 18 suggests that long-term achievement of a single A credit rating is in a utility company's and its ratepayers' best interests. Debt leverage targets should be set in the lower part of the range required to attain this optimal rating. If the company maintains its debt ratio close to the optimal range required for a single A bond rating, its overall cost of capital should be minimized. If the company reduces its debt ratio below that point, it would be giving up the tax benefits associated with debt but would not reap the benefits from a lower cost of debt and equity. If the company operates at a debt ratio beyond that point, the cost of debt and equity will rise. The latter rise will occur at an increasing rate if the operating environment deteriorates. Moreover, the company will reduce its financing flexibility.

To summarize, in theory, there exists an optimal capital structure, i.e., one that minimizes the WACC. Financing the assets with a blend of debt and equity can lower the overall WACC, because debt is less expensive than equity owing to its tax advantage and lower risk. However, too much debt will increase the WACC, as the risks associated with debt will outweigh its benefits. In practice, there exists a range of capital structures over which the average cost of capital does not change materially. Within this range, an increase in the debt ratio will result in an increase in both the cost of debt and the cost of equity, but the overall cost of capital will not change measurably.

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DOD-IR-50

[Morin Direct, p. 70, ll. 9-12]

What is the source of Dr. Morin's understanding regarding what bond rating agencies would or would not do regarding debt equivalents if the ECAC were not in existence? Provide supporting documentation.

Dr. Morin's Response:

As stated in his direct testimony, Dr. Morin believes that in the absence of the ECAC mechanism, not only would HECO's financial condition deteriorate, but its credit ratings would likely be under review for possible downgrade, its customers would be at risk of having to pay higher rates due to access to capital becoming more expensive for HECO, and his recommended return would be significantly higher. This situation would have a substantial negative effect on HECO and its customers because of the magnitude of the energy cost component in its cost of service.

DOD-IR-51

[Morin Direct, p. 70, ll. 17-20]

Which companies in Dr. Morin's sample groups have automatic fuel adjustment clauses?

Dr. Morin's Response:

As shown in the table on page 2 (Moody's "Rating Methodology: Global Regulated Electric Utilities," March 2005 Figure 8), the approval of adjustment clauses, riders, and cost recovery mechanisms by regulatory commissions is widespread in the utility business and is already largely embedded in financial data, such as bond rating. Most, if not all, companies that make up Dr. Morin's comparable groups are under some form of adjustment clause/cost recovery mechanism. The table on page 2 shows that 41 of the 51 state regulatory jurisdictions (including District of Columbia) have various policies with respect to fuel and wholesale power cost recovery. All else remaining constant, such clauses reduce investment risk on an absolute basis and constitute sound regulatory policy.

Of course, while adjustment clauses and cost tracking mechanisms may mitigate (on an absolute basis but not on a relative basis) a portion of the risk and uncertainty related to the day-to-day management of a regulated utility's operations, there are other significant factors to consider that may work in the reverse direction.

	State	**Cost Recovery**
1	Alabama	X
2	Alaska	n/a
3	Arizona	X
4	Arkansas	X
5	California	X
6	Colorado	X
7	Connecticut	X
8	Delaware	X
9	DC	
10	Florida	X
11	Georgia	X
12	Hawaii	X
13	Idaho	X
14	Illinois	X
15	Indiana	X
16	Iowa	X
17	Kansas	X
18	Kentucky	X
19	Louisiana	X
20	Maine	X
21	Maryland	
22	Massachusetts	X
23	Michigan	X
24	Minnesota	X
25	Mississippi	X
26	Missouri	
27	Montana	
28	Nebraska	n/a
29	Nevada	X
30	New Hampshire	X
31	New Jersey	X
32	New Mexico	
33	New York	X
34	North Carolina	X
35	North Dakota	X
36	Ohio	
37	Oklahoma	X
38	Oregon	X
39	Pennsylvania	

n/a – Not-applicable
X – State has some form of adjustment clause/cost recovery mechanism in place.

	State	Cost Recovery
40	Rhode Island	X
41	South Carolina	X
42	South Dakota	X
43	Tennessee	X
44	Texas	X
45	Utah	
46	Vermont	
47	Virginia	
48	Washington	X
49	West Virginia	X
50	Wisconsin	X
51	Wyoming	X

n/a – Not-applicable
X – State has some form of adjustment clause/cost recovery mechanism in place.

DOD-IR-52

[Morin Direct, p. 72, l. 8]

Please define financial risk.

Dr. Morin's Response:

Financial risk stems from the method used by the company to finance its investments and is reflected in its capital structure. It refers to the additional variability imparted to income available to common shareholders by the employment of fixed cost financing, that is, debt and preferred stock capital. Although the use of fixed cost capital can offer financial advantages through the possibility of leverage of earnings (financial leverage), it creates additional risk due to the fixed contractual obligations associated with such capital. Debt and preferred stock carry fixed charge burdens that must be supported by the company's earnings before any return can be made available to the common shareholder. The greater the percentage of fixed charges to the total income of the company, the greater the financial risk. The use of fixed cost financing introduces additional variability into the pattern of net earnings over and above that already conferred by business risk.

DOD-IR-53

[Morin Direct, HECO-1801, p. 1]

a. Please provide the percent of revenues from electric operations for each of the companies listed.

b. Please provide the bond ratings of each of the companies listed.

c. Please provide the amount of purchased power used by each company.

d. Please provide the percent of common equity in each company's capital structure.

<u>Dr. Morin's Response:</u>

a. The requested information is provided in response to DOD-IR-35.

b. The requested information is provided in response to DOD-IR-35.

c. Dr. Morin does not have access to the dollar amounts of purchased power used by individual electric utilities.

d. The requested information is provided in response to DOD-IR-35.

Note: Most (if not all) of the information requested is copyrighted. The copy is being provided under the "fair use" exception to the copyright laws. Any copies made of the requested information are subject to copyright laws.

DOD-IR-54

[Morin Direct, HECO-1801, p. 2]

a. Please provide the percent of revenues from electric operations for each of the companies listed.

b. Please provide the bond ratings of each of the companies listed.

c. Please provide the amount of purchased power used by each company.

d. Please provide the percent of common equity in each company's capital structure.

Dr. Morin's Response:

a. The requested information is provided in response to DOD-IR-35.

b. The requested information is provided in response to DOD-IR-35.

c. Dr. Morin does not have access to the dollar amounts of purchased power used by individual electric utilities.

d. The requested information is provided in response to DOD-IR-35.

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DOD-IR-55

[Morin Direct, HECO-1802]

Please provide an electronic copy of HECO-1802, with cells unlocked and formulas available.

Dr. Morin's Response:

See attached.

MOODY'S ELECTRIC UTILITY COMMON STOCKS
OVER LONG-TERM TREASURY BONDS
ANNUAL LONG-TERM RISK PREMIUM ANALYSIS

Year	Long-Term Government Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	Moody's Electric Utility Stock Index	Dividend	Capital Gain/(Loss) % Growth	Yield	Stock Total Return	Equity Risk Premium
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1931	4.07%	1,000.00				43.23					
1932	3.15%	1,135.75	135.75	40.70	17.64%	39.42	2.22	-8.81%	5.14%	-3.68%	-21.32%
1933	3.36%	969.60	-30.40	31.50	0.11%	28.73	1.75	-27.12%	4.44%	-22.68%	-22.79%
1934	2.93%	1,064.73	64.73	33.60	9.83%	21.06	1.42	-26.70%	4.94%	-21.75%	-31.59%
1935	2.76%	1,025.99	25.99	29.30	5.53%	36.06	1.33	71.23%	6.32%	77.54%	72.01%
1936	2.55%	1,032.74	32.74	27.60	6.03%	41.60	1.78	15.36%	4.94%	20.30%	14.27%
1937	2.73%	972.40	-27.60	25.50	-0.21%	24.24	1.68	-41.73%	4.04%	-37.69%	-37.48%
1938	2.52%	1,032.83	32.83	27.30	6.01%	27.55	1.45	13.66%	5.98%	19.64%	13.62%
1939	2.26%	1,041.65	41.65	25.20	6.68%	28.85	1.51	4.72%	5.48%	10.20%	3.51%
1940	1.94%	1,052.84	52.84	22.60	7.54%	22.22	1.57	-22.98%	5.44%	-17.54%	-25.08%
1941	2.04%	983.64	-16.36	19.40	0.30%	13.45	1.27	-39.47%	5.72%	-33.75%	-34.06%
1942	2.46%	933.97	-66.03	20.40	-4.56%	14.29	1.28	6.25%	9.52%	15.76%	20.33%
1943	2.48%	996.86	-3.14	24.60	2.15%	21.01	1.46	47.03%	10.22%	57.24%	55.10%
1944	2.46%	1,003.14	3.14	24.80	2.79%	21.09	1.35	0.38%	6.43%	6.81%	4.01%
1945	1.99%	1,077.23	77.23	24.60	10.18%	31.14	1.37	47.65%	6.50%	54.15%	43.97%
1946	2.12%	978.90	-21.10	19.90	-0.12%	32.71	1.48	5.04%	4.75%	9.79%	9.91%
1947	2.43%	951.13	-48.87	21.20	-2.77%	25.60	1.58	-21.74%	4.83%	-16.91%	-14.14%
1948	2.37%	1,009.51	9.51	24.30	3.38%	26.20	1.63	2.34%	6.37%	8.71%	5.33%
1949	2.09%	1,045.58	45.58	23.70	6.93%	30.57	1.68	16.68%	6.41%	23.09%	16.16%
1950	2.24%	975.93	-24.07	20.90	-0.32%	30.81	1.85	0.79%	6.05%	6.84%	7.15%
1951	2.69%	930.75	-69.25	22.40	-4.69%	33.85	1.90	9.87%	6.17%	16.03%	20.72%
1952	2.79%	984.75	-15.25	26.90	1.17%	37.85	1.92	11.82%	5.67%	17.49%	16.32%
1953	2.74%	1,007.66	7.66	27.90	3.56%	39.61	2.09	4.65%	5.52%	10.17%	6.62%
1954	2.72%	1,003.07	3.07	27.40	3.05%	47.56	2.14	20.07%	5.40%	25.47%	22.43%
1955	2.95%	965.44	-34.56	27.20	-0.74%	49.35	2.27	3.76%	4.77%	8.54%	9.27%
1956	3.45%	928.19	-71.81	29.50	-4.23%	48.96	2.37	-0.79%	4.80%	4.01%	8.24%
1957	3.23%	1,032.23	32.23	34.50	6.67%	50.30	2.46	2.74%	5.02%	7.76%	1.09%
1958	3.82%	918.01	-81.99	32.30	-4.97%	66.37	2.57	31.95%	5.11%	37.06%	42.03%
1959	4.47%	914.65	-85.35	38.20	-4.71%	65.77	2.64	-0.90%	3.98%	3.07%	7.79%
1960	3.80%	1,093.27	93.27	44.70	13.80%	76.82	2.74	16.80%	4.17%	20.97%	7.17%
1961	4.15%	952.75	-47.25	38.00	-0.92%	99.32	2.86	29.29%	3.72%	33.01%	33.94%
1962	3.95%	1,027.48	27.48	41.50	6.90%	96.49	3.07	-2.85%	3.09%	0.24%	-6.66%

MOODY'S ELECTRIC UTILITY COMMON STOCKS
OVER LONG-TERM TREASURY BONDS
ANNUAL LONG-TERM RISK PREMIUM ANALYSIS

Year	Long-Term Government Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	Moody's Electric Utility Stock Index	Dividend	Capital Gain/(Loss) % Growth	Yield	Stock Total Return	Equity Risk Premium
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1963	4.17%	970.35	-29.65	39.50	0.99%	102.31	3.33	6.03%	3.45%	9.48%	8.50%
1964	4.23%	991.96	-8.04	41.70	3.37%	115.54	3.68	12.93%	3.60%	16.53%	13.16%
1965	4.50%	964.64	-35.36	42.30	0.69%	114.86	4.02	-0.59%	3.48%	2.89%	2.20%
1966	4.55%	993.48	-6.52	45.00	3.85%	105.99	4.18	-7.72%	3.64%	-4.08%	-7.93%
1967	5.56%	879.01	-120.99	45.50	-7.55%	98.19	4.44	-7.36%	4.19%	-3.17%	4.38%
1968	5.98%	951.38	-48.62	55.60	0.70%	104.04	4.58	5.96%	4.66%	10.62%	9.92%
1969	6.87%	904.00	-96.00	59.80	-3.62%	84.62	4.63	-18.67%	4.45%	-14.22%	-10.60%
1970	6.48%	1,043.38	43.38	68.70	11.21%	88.59	4.73	4.69%	5.59%	10.28%	-0.93%
1971	5.97%	1,059.09	59.09	64.80	12.39%	85.56	4.81	-3.42%	5.43%	2.01%	-10.38%
1972	5.99%	997.69	-2.31	59.70	5.74%	83.61	4.92	-2.28%	5.75%	3.47%	-2.27%
1973	7.26%	867.09	-132.91	59.90	-7.30%	60.87	5.04	-27.20%	6.03%	-21.17%	-13.87%
1974	7.60%	965.33	-34.67	72.60	3.79%	41.17	4.83	-32.36%	7.93%	-24.43%	-28.22%
1975	8.05%	955.63	-44.37	76.00	3.16%	55.66	4.99	35.20%	12.12%	47.32%	44.15%
1976	7.21%	1,088.25	88.25	80.50	16.87%	66.29	5.25	19.10%	9.43%	28.53%	11.66%
1977	8.03%	919.03	-80.97	72.10	-0.89%	68.19	5.68	2.87%	8.57%	11.43%	12.32%
1978	8.98%	912.47	-87.53	80.30	-0.72%	59.75	5.98	-12.38%	8.77%	-3.61%	-2.88%
1979	10.12%	902.99	-97.01	89.80	-0.72%	56.41	6.34	-5.59%	10.61%	5.02%	5.74%
1980	11.99%	859.23	-140.77	101.20	-3.96%	54.42	6.67	-3.53%	11.82%	8.30%	12.25%
1981	13.34%	906.45	-93.55	119.90	2.63%	57.20	7.16	5.11%	13.16%	18.27%	15.63%
1982	10.95%	1,192.38	192.38	133.40	32.58%	70.26	7.64	22.83%	13.36%	36.19%	3.61%
1983	11.97%	923.12	-76.88	109.50	3.26%	72.03	8.00	2.52%	11.39%	13.91%	10.64%
1984	11.70%	1,020.70	20.70	119.70	14.04%	80.16	8.37	11.29%	11.62%	22.91%	8.87%
1985	9.56%	1,189.27	189.27	117.00	30.63%	94.98	8.71	18.49%	10.87%	29.35%	-1.27%
1986	7.89%	1,166.63	166.63	95.60	26.22%	113.66	8.97	19.67%	9.44%	29.11%	2.89%
1987	9.20%	881.17	-118.83	78.90	-3.99%	94.24	9.12	-17.09%	8.02%	-9.06%	-5.07%
1988	9.18%	1,001.82	1.82	92.00	9.38%	100.94	8.71	7.11%	9.24%	16.35%	6.97%
1989	8.16%	1,099.75	99.75	91.80	19.16%	122.52	8.85	21.38%	8.77%	30.15%	10.99%
1990	8.44%	973.17	-26.83	81.60	5.48%	117.77	8.76	-3.88%	7.15%	3.27%	-2.20%
1991	7.30%	1,118.94	118.94	84.40	20.33%	144.02	9.02	22.29%	7.66%	29.95%	9.61%
1992	7.26%	1,004.19	4.19	73.00	7.72%	141.06	8.82	-2.06%	6.12%	4.07%	-3.65%
1993	6.54%	1,079.70	79.70	72.60	15.23%	146.70	9.04	4.00%	6.41%	10.41%	-4.82%
1994	7.99%	856.40	-143.60	65.40	-7.82%	115.50	9.01	-21.27%	6.14%	-15.13%	-7.31%

MOODY'S ELECTRIC UTILITY COMMON STOCKS
OVER LONG-TERM TREASURY BONDS
ANNUAL LONG-TERM RISK PREMIUM ANALYSIS

Year	Long-Term Government Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	Moody's Electric Utility Stock Index	Dividend	Capital Gain/(Loss) % Growth	Yield	Stock Total Return	Equity Risk Premium
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1995	6.03%	1,225.98	225.98	79.90	30.59%	142.90	9.06	23.72%	7.84%	31.57%	0.98%
1996	6.73%	923.67	-76.33	60.30	-1.60%	136.00	9.06	-4.83%	6.34%	1.51%	3.11%
1997	6.02%	1,081.92	81.92	67.30	14.92%	155.73	9.06	14.51%	6.66%	21.17%	6.25%
1998	5.42%	1,072.71	72.71	60.20	13.29%	181.44	8.01	16.51%	5.14%	21.65%	8.36%
1999	6.82%	848.41	-151.59	54.20	-9.74%	137.30	8.71	-24.33%	4.80%	-19.53%	-9.79%
2000	5.58%	1,148.30	148.30	68.20	21.65%	227.09	8.71	65.40%	6.34%	71.74%	50.09%
2001	5.75%	979.95	-20.05	55.80	3.57%	214.08	8.56	-5.73%	3.77%	-1.96%	-5.54%
Mean											**5.62%**

Source: Mergent's (Moody's) Public Utility Manual 2002 December stock prices and dividends
Dec. Bond yields from Ibbotson Associates 2002 Yearbook Table B-9 Long-Term Government Bonds Yields

DOD-IR-56

[Morin Direct, HECO-1809, p. 8]

If the example is the same, but the market-to-book ratio is 1.0, is the resulting growth rate greater or less then the assumed 5%? Why?

Dr. Morin's Response:

The market-to-book ratio cannot be 1.0 because the company nets an amount less than the market price whenever it issues common stock, namely, $95 in the example versus a stock price of $100.

DOD-IR-57

Please provide a complete copy of Dr. Morin's workpapers and articles cited in his Testimony not otherwise requested in the above interrogatories.

<u>Dr. Morin's Response:</u>

Other than the materials provided in the responses to the above interrogatories, the data in Dr. Morin's exhibits are constructed from commercially available information services obtained on a paid subscription basis on CD-ROMs updated monthly, primarily the Value Line Investment Analyzer. The information contained in the Value Line Investment Analyzer software cannot be supplied electronically in order to avoid violation of copyright laws. Dr. Morin notes that much of the information contained in the Value Line Investment Analyzer software is available in paper format from the latest edition of the traditional Value Line Investment Survey coinciding with the month of publication of the software version. Such reports are available at most university libraries in paper format.

Analysts' growth forecasts are obtained directly online from Zacks Investment Research Web site and are available by commercial paid subscription to members. Material that is proprietary can be made available for inspection upon reasonable prior notice at the Company's premises.

Copies of the Moody's (now Mergent) Public Utility Manual reference cited in the footnotes of Exhibit HECO-1802 are available in most respectable libraries and regulatory commission libraries. The bond yields were obtained from Ibbotson Associates "Yearbook" of historical returns, Table B-6 "Long-Term Government Bond Yields". This widely used reference is available by paid commercial subscription only and cannot be disseminated without violating copyright laws, and can certainly be made available for inspection upon reasonable prior notice at the Company's premises.

DOD-IR-58

Sekimura Direct, p. 3, ll. 2-4.

Please list the capital structure, embedded cost rates and cost of equity requested by the Company in Docket Nos., 7766, 7700, and 6998.

HECO Response:

Please refer to HECO's response to DOD/HECO-IR-3-39 in Docket No. 04-0113 (HECO's 2005 Test Year Rate Case) filed on April 13, 2005.

DOD-IR-59

Sekimura Direct, p. 5.

Please explain why a financial manager would not want to obtain funds at the lowest possible cost rather than the lowest "reasonable" cost. What is the difference between the lowest possible cost and the lowest reasonable cost?

HECO Response:

Obtaining funds at the lowest "possible" cost implies that a company would make its decision based solely on the cost of financing (i.e., interest rate or return). The Company describes obtaining funds at the lowest "reasonable" cost because its financing decisions are not solely based on cost (i.e., interest rate or return), but also take into consideration the term and flexibility that the financing provides. Funding at the lowest "reasonable" cost helps to maintain a capital structure (balancing debt and equity) that would provide financial stability and flexibility so the company would have the ability to consistently attract new capital on reasonable terms, when capital is needed. Continuous access to the capital markets is critical for a capital-intensive company such as HECO that has an obligation to provide utility services. Ratepayers benefit by having a greater assurance that utility investments can be financed when needed.

DOD-IR-60

Sekimura Direct, p. 6, ll. 4.

To Ms. Sekimura's knowledge, has HECO ever been unable to access the capital markets? If so, please provide any available evidence that such an event occurred.

HECO Response:

I, Tayne Sekimura, have been the Financial Vice President for HECO from October 2004 to the present, and I am not aware of HECO being unable to access the capital markets during this period. However, during the 9/11 crisis, HECO was cut off from the commercial paper market (not due to lack of financial integrity) and had to borrow money from Bank of Hawaii instead. This experience across the industry caused the rating agencies to ask what alternatives companies had in the event of such a situation and demonstrates the need to maintain financial integrity in order to have ready access to alternative sources of funds.

DOD-IR-61

<u>Sekimura Direct, p. 8, ll. 12, 13.</u>

Does the ability of HECO to recover purchased power expenses that are different from the level included in rates affect S&P's calculation of debt-equivalency? If not, please explain why not and provide any available supporting analysis from S&P; if so, please explain how and provide support from S&P regarding the change in calculation of debt equivalents.

<u>HECO Response:</u>

As discussed in S&P's May 7, 2007 article (see HECO's response to DOD-IR-68, pages 2 to 7), S&P calculates the debt equivalent based on the NPV of capacity payments using a discount rate equivalent to the company's average cost of debt, net of securitization debt, and then applies a risk factor to reflect the benefits of regulatory or legislative cost recovery mechanisms. In the article, S&P states:

> "The NPVs that Standard & Poor's calculates to adjust reported financial metrics to capture PPA capacity payments are multiplied by risk factors. These risk factors typically range between 0% and 50%, but can be as high as 100%. Risk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements. The strongest recovery mechanisms translate into the smallest risk factors. A 100% risk factor would signify that all risk related to contractual obligations rests on the company with no mitigating regulatory or legislative support."

Therefore, HECO's mechanism to recover its fixed costs created by PPAs does have an impact on the risk factor that S&P assigns to the Company in calculating the Company's debt equivalent (see further discussion in HECO's response to DOD-IR-68). Thus, a weak recovery mechanism translates to a higher risk factor, which would result in a higher adjusted total debt/total capital ratio for the Company, which can negatively impact the Company's credit quality.

DOD-IR-62

Sekimura Direct, p. 13.

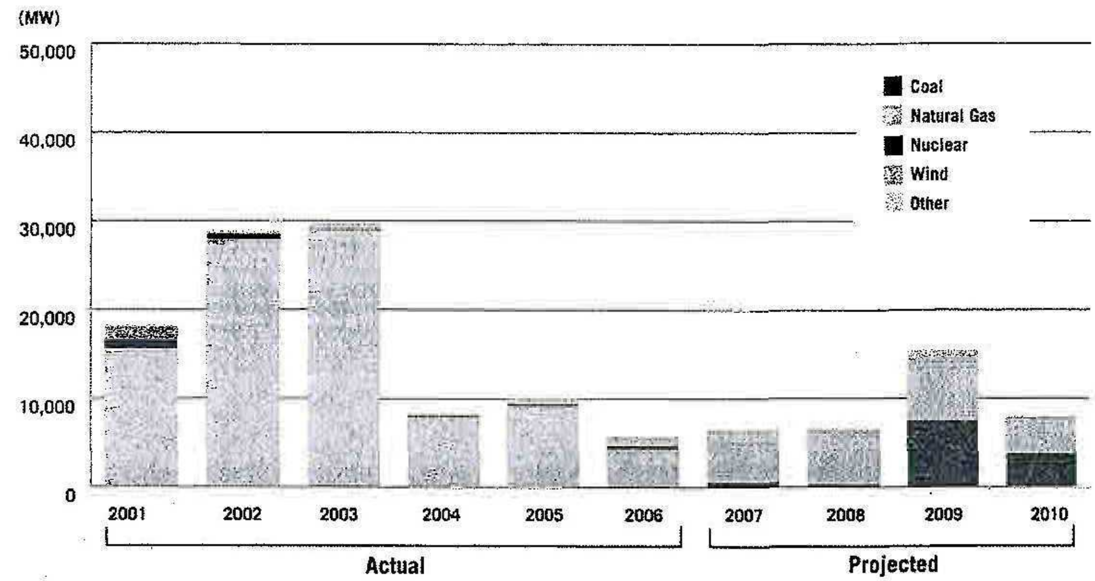
Are HECO's construction plans for additional generation and transmission infrastructure extraordinarily large, when compared to industry averages? Please provide support for your response.

HECO Response:

Ms. Sekimura is not aware of industry averages for forecast capital expenditures. However, the Company's construction plans appear to be consistent with trends and plans for the electric industry as described in the article reflected on pages 2 and 3 of this response. For example, the Edison Electric Institute 2006 Financial Review: Annual Report of the Shareholder-Owned Electric Utility Industry, dated April 27, 2007 ("EEI 2006 Financial Review"), projects the addition of 15,529 MW of new generation in 2009 among US investor-owned electric utilities compared with 5,857 MW in 2006, nearly a three-fold increase (see page 2). The EEI 2006 Financial Review also projects transmission and distribution investments to increase from $5,803 million in 2005 to $8,354 million in 2009 (see page 3).

Actual and Projected Capacity Additions 2001-2010

U.S. SHAREHOLDER-OWNED ELECTRIC UTILITIES



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Coal	—	—	91	—	—	110	569	350	7,541	3,821
Natural Gas	15,687	28,073	28,960	8,054	9,255	4,343	4,403	5,789	6,548	4,042
Nuclear	1,058	602	109	79	247	350	—	—	—	—
Wind	1,478	173	658	307	780	1,000	1,642	567	540	—
Other	154	118	3	3	2	54	7	11	900	125
Total	**18,378**	**28,966**	**29,821**	**8,442**	**10,284**	**5,857**	**6,621**	**6,717**	**15,529**	**7,988**

Notes: Data includes new plants and expansions of existing plants, including nuclear uprates.
2001-2006 is actual plants brought online. 2007-2010 is projected based on projects announced as of 12/31/06.

Source: Global Energy Decisions, Inc., The Velocity Suite, Nuclear Energy Institute, and EEI Finance Department

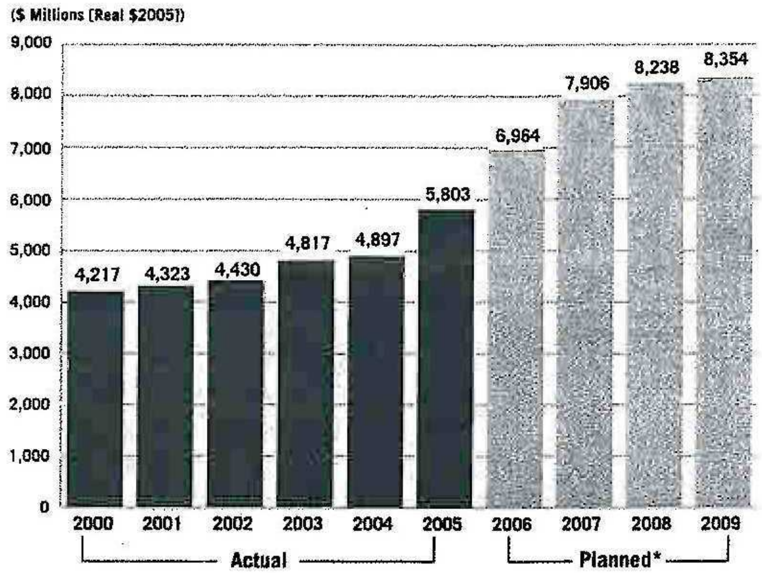
Five shareholder-owned electric utilities did announce plans last year for new IGCC plants. TECO Energy, Southern Company, Duke Energy, CMS Energy and Sierra Pacific Resources plan to build a total of 2,830 MW, expected online between 2012 and 2016. TECO, Duke and Southern were each awarded $133 million in IRS tax credits for the plants, under guidelines established by the Energy Policy Act of 2005 (EPAct 2005). The projects were evaluated for technical and economic feasibility and for consistency with DOE energy policy goals, such as furthering the deployment of clean coal-based generation technologies.

In addition to TXU, SCANA and Progress Energy also announced plans to build new nuclear plants. SCANA intends to build up to two new units at its existing V.C. Summer site in South Carolina, using the AP1000 reactor design. The company anticipates submitting an application for a construction and operating license (COL) to the Nuclear Regulatory Commission later this year. The first unit would be operational by 2015 and add up to 1,117 MW to the grid. Progress announced plans for a second new nuclear plant, in Levy County, FL, following an earlier announcement of plans for a new nuclear facility in North Carolina. In contrast to most companies pursuing new nuclear plants, Progress has decided to build the second proposed plant at a "greenfield" site rather than at the site of an existing nuclear unit. The issued an amended final order establishing transmission pricing incentives that allow a higher return-on-equity (ROE) and recovery of pre-construction costs in situations where a project will reduce congestion and improve reliability. The preceding month, FERC finalized a rule to implement its new backstop siting authority, under which the Commission can issue a construction permit for a transmission project to an applicant in a limited set of circumstances.

Backstop Siting—EPAct 2005 reflected a largely consensus view in Congress that the buildout of new transmission infrastructure in the U.S. was not occurring rapidly enough to address reliability and load growth issues, despite savings achieved through efficiency measures. One impediment identified was that the siting process for transmission was not well-suited to interstate facilities that transmit power long distances with sometimes limited local benefits. The legislation attempted to remedy the situation by giving FERC the ability to issue permits to modify or construct transmission facilities located in National Interest Electric Transmission Corridors (NIETC) designated by DOE when:

- The state does not have authority to issue the permit or consider the regional benefits of a facility;
- The applicant is not a load-serving entity eligible to seek a state permit;
- The state commission withholds approval of the permit for more than one year after the application is filed; or,
- The state commission conditions the permit in such a manner that the facilities will not relieve transmission congestion or will be rendered economically infeasible.

Actual and Planned Transmission Investment 2000-2009



Note: In 2004 and 2005, the industry exceeded investment projections in their transmission capital budgets. *The Handy-Whitman Index of Public Utility Construction Costs* used to adjust for inflation from year to year. Data represent both shareholder-owned utilities and stand-alone transmission companies.

*Planned total industry expenditures are estimated from 90% response rate to EEI's Electric Transmission Capital Budget & Forecast Survey. Actual expenditures from EEI's Annual Property & Plant Capital Investment Survey & FERC Form 1s.

Source: EEI Business Information Group

The backstop siting rule outlines the procedures and requirements for pursuing a construction permit through FERC. Consistent with FERC's view that its authorities supplement–rather than replace–existing state siting authorities, the pre-filing process established by FERC can not begin until one year after an application has been filed in the relevant state(s) (in cases where the state has the authority to site facilities). FERC will thoroughly review all applications to ensure that proposed facilities are in the public interest, will be used for interstate electric transmission, will reduce congestion, will make the best use of existing structures, and are consistent with sound energy policy goals.

Transmission Incentives—In Order 679-A, "Promoting Transmission Investment through Pricing Reform", FERC established a series of incentives designed to help reduce financial risk in transmission construction projects. Included among these are an incentive-based ROE within a zone of reasonableness, upfront ROE determination, incentives for transco formation, incentives for public utilities to join an RTO/ISO, timely recovery of prudently incurred costs, inclusion of 100% of construction work-in-progress (CWIP) in rate base, and expensing of pre-commercial operations costs associated with the project.

Applicants must demonstrate a relationship between the total package of requested incentives and project risks. The Commission has stated that it does not intend to routinely grant incentive returns at the high end of the

DOD-IR-63

Sekimura Direct, p. 14, ll. 14, 15.

Is it also true for depreciation expense, taxes and corporate overhead that those expenses must be paid "before shareholders receive any compensation for the use of their funds? If not, please explain why not.

HECO Response:

Taxes and corporate overhead are expenses that must be paid before shareholders receive compensation for the use of their funds. Although depreciation expense is a non-cash item, it is a deduction, like taxes and corporate overhead, from revenue in determining net income which is the return on shareholders' investment.

DOD-IR-64

Sekimura Direct, p. 15.

Please explain how a competitive bidding requirement could impact HECO's financial performance. Provide actual examples from Company experience.

HECO Response:

In theory, a competitive bidding process could be executed in a manner which changes the utility's business and financial risk profiles. Changes in the utility's risk profiles could result in changes in financial performance. The Company has no actual experience in competitive bidding under the recently-issued Framework for Competitive Bidding.

DOD-IR-65

Sekimura Direct, p. 24.

What has been the S&P bond rating for HEI and HECO each year from 2000 through 2006? Please provide support for your response.

HECO Response:

Please refer to HECO's response to CA-IR-11 in this rate proceeding.

DOD-IR-66

<u>Sekimura Direct, p. 27.</u>

Does the potential change in accounting for pension and post-retirement benefits mean that the Company will have to more accurately assess its pension fund parameters in the future, or does the Company believe that it makes those estimates accurately now?

<u>HECO Response:</u>

The Company believes that its estimates of pension and post-retirement benefits are as accurate as possible, given the guidance and information available at the time the estimates are made. As discussed in the testimony, Statement of Financial Accounting Standards No. 158, "Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans", ("SFAS No. 158") was implemented on December 31, 2006. SFAS No. 87, "Employers' Accounting for Pensions", is the primary accounting guidance used to determine the method and assumptions underlying the actuarial projections of pension obligations. SFAS No. 158 did not change that portion of SFAS No. 87. The assumptions used in making benefit and funding calculations were in the past, and will continue to be, based on current economic conditions at the time of the projection. The pension plan's actuarial consultant provides guidance and the method, assumptions, and results are reviewed by the Company's external auditors.

DOD-IR-67

Sekimura Direct, p. 32.

a) Please provide a complete copy of the ICC order cited in footnote 15.

b) Is it Ms. Sekimura's testimony that pension fund asset disallowance was the sole cause of the bond rating downgrade? What other factors were involved?

HECO Response:

a. The requested information (pages 2 to 324) is voluminous and is available for inspection at HECO's Regulatory Affairs Division office, Suite 1301, Central Pacific Plaza, 220 South King Street, Honolulu, Hawaii. Please contact Dean Matsuura at 543-4622 to make arrangements to inspect the requested information.

b. No, rather it is Ms. Sekimura's testimony that the pension asset disallowance contributed to the bond rating downgrade. Factors involved in the downgrade included the difficult political and regulatory environment in Illinois. The pension asset disallowance was part of the unfavorable rate order indicative of the difficult regulatory environment.

The requested information (pages 2 to 324) is voluminous and is available for inspection at HECO's Regulatory Affairs Division office, Suite 1301, Central Pacific Plaza, 220 South King Street, Honolulu, Hawaii. Please contact Dean Matsuura at 543-4622 to make arrangements to inspect the requested information.

DOD-IR-68

<u>Sekimura Direct, p. 38, l. 9.</u>

Is a 30% risk factor assigned to all of HECO's purchased power contracts? If not, please list each contract and indicate what the S&P risk factor is for each.

HECO Response:

On May 7, 2007, S&P issued a publication titled "Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements" (see pages 3 to 8). Based on this article, it is our understanding that HECO's firm capacity purchased power contracts will now be assigned a 50% risk factor, rather than the 30% risk factor previously used by S&P. The article states:

> "Risk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements. The strongest recovery mechanisms translate into the smallest risk factors……Intermediate degrees of recovery risk are presented by a number of regulatory and legislative mechanisms. For example, some regulators use a utility's rate case to establish base rates that provide for the recovery of the fixed costs created by PPAs. Although we see this type of mechanism as generally supportive of credit quality, the fact remains that the utility will need to litigate the right to recover costs and the prudence of PPA capacity payments in successive rate cases to ensure ongoing recovery of its fixed costs. For such a PPA, we employ a 50% risk factor."

Therefore, since HECO's fixed costs created by PPAs are being recovered through base rates, it is our understanding that all of HECO's firm capacity purchased power contracts are now assigned a 50% risk factor. In addition, the S&P article discusses an "evergreen treatment" of PPAs which extend the expected period of fixed payments to a minimum of twelve years.

As a result of the increase in the risk factor from 30% (as presented in Direct Testimony, T-19) to 50%, and S&P's evergreen treatment (per S&P's May 7, 2007 publication), HECO's revised 2007 average debt equivalent of $464,458 (see page 9) is $207,567 higher than the 2007 average debt equivalent presented in HECO-WP-1913. See pages 13 to 25 for HECO's 2007 revised financial ratios which incorporate the Company's understanding of S&P's current methodology of imputing debt for purchase power agreements and adjustments made to the financial ratios (i.e., implied interest and implied depreciation). The higher debt equivalent adjustment for HECO results in a higher adjusted total debt/total capital ratio (see page 13), which negatively impacts the Company's credit quality.

RESEARCH

Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

Publication date: 07-May-2007
Primary Credit Analyst: David Bodek, New York (1) 212-438-7969; david_bodek@standardandpoors.com
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Solomon B Samson, New York (1) 212-438-7653; sol_samson@standardandpoors.com

For many years, Standard & Poor's Ratings Services has viewed power supply agreements (PPA) in the U.S. utility sector as creating fixed, debt-like, financial obligations that represent substitutes for debt-financed capital investments in generation capacity. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. Consequently, PPA fixed obligations, in the form of capacity payments, merit inclusion in a utility's financial metrics as though they are part of a utility's permanent capital structure and are incorporated in our assessment of a utility's creditworthiness.

We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates.

The Mechanics Of PPA Debt Imputation

A starting point for calculating the debt to be imputed for PPA-related fixed obligations can be found among the "commitments and contingencies" in the notes to a utility's financial statements. We calculate a net present value (NPV) of the stream of the outstanding contracts' capacity payments reported in the financial statements as the foundation of our financial adjustments.

The notes to the financial statements enumerate capacity payments for the five years succeeding the annual report and a "thereafter" period. While we have access to proprietary forecasts that show the detail underlying the costs that are amalgamated beyond the five-year horizon, others, for purposes of calculating an NPV, can divide the amount reported as "thereafter" by the average of the capacity payments in the preceding five years to derive an approximate tenor of the amounts combined as the sum of the obligations beyond the fifth year.

In calculating debt equivalents, we also include new contracts that will commence during the forecast period. Such contracts aren't reflected in the notes to the financial statements, but relevant information regarding these contracts are provided to us on a confidential basis. If a contract has been executed but the energy will not flow until some later period, we won't impute debt for that contract until the year that energy deliveries begin under the contract if the contract represents incremental capacity. However, to the extent that the contract will simply replace an expiring contract, we will impute debt as though the future contract is a continuation of the existing contract.

We calculate the NPV of capacity payments using a discount rate equivalent to the company's average cost of debt, net of securitization debt. Once we arrive at the NPV, we apply a risk factor, as is discussed below, to reflect the benefits of regulatory or legislative cost recovery mechanisms.

Balance sheet debt is increased by the risk-factor-adjusted NPV of the stream of capacity payments. We derive an adjusted debt-to-capitalization ratio by adding the adjusted NPV to both the numerator and the denominator of that ratio.

We calculate an implied interest expense for the imputed debt by multiplying the same utility average cost of debt used as the discount rate in the NPV calculation by the amount of imputed debt. The adjusted FFO-to-interest expense ratio is calculated by adding the implied interest expense to both the numerator and denominator of the equation. We also add implied depreciation to the equation's numerator. We calculate the adjusted FFO-to-total-debt ratio by adding imputed debt to the equation's denominator and an implied depreciation expense to its numerator.

Our adjusted cash flow credit metrics include a depreciation expense adjustment to FFO. This adjustment represents a vehicle for capturing the ownership-like attributes of the contracted asset and tempers the effects of imputation on the cash flow ratios. We derive the depreciation expense adjustment by multiplying the relevant year's capacity payment obligation by the risk factor and then subtracting the implied PPA-related interest expense for that year from the product of the risk factor times the scheduled capacity payment.

Risk Factors

The NPVs that Standard & Poor's calculates to adjust reported financial metrics to capture PPA capacity payments are multiplied by risk factors. These risk factors typically range between 0% to 50%, but can be as high as 100%. Risk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements. The strongest recovery mechanisms translate into the smallest risk factors. A 100% risk factor would signify that all risk related to contractual obligations rests on the company with no mitigating regulatory or legislative support.

For example, an unregulated energy company that has entered into a tolling arrangement with a third-party supplier would be assigned a 100% risk factor. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers. This type of arrangement is frequently found among regulated utilities that act as conduits for the delivery of a third party's electricity and essentially deliver power, collect charges, and remit revenues to the suppliers. These utilities have typically been directed to sell all their generation assets, are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties, leaving the utilities to act as intermediaries between retail customers and the electricity suppliers.

Intermediate degrees of recovery risk are presented by a number of regulatory and legislative mechanisms. For example, some regulators use a utility's rate case to establish base rates that provide for the recovery of the fixed costs created by PPAs. Although we see this type of mechanism as generally supportive of credit quality, the fact remains that the utility will need to litigate the right to recover costs and the prudence of PPA capacity payments in successive rate cases to ensure ongoing recovery of its fixed costs. For such a PPA, we employ a 50% risk factor. In cases where a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, we employ a risk factor of 25% because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recover costs.

We recognize that there are certain jurisdictions that have true-up mechanisms that are more favorable and frequent than the review of base rates, but still don't amount to pure pass-through mechanisms. Some of these mechanisms are triggered when certain financial thresholds are met or after prescribed periods of time have passed. In these instances, in calculating adjusted ratios, we will employ a risk factor between the revised 25% risk factors for utilities with power cost adjustment mechanisms and 50%.

Finally, we view legislatively created cost recovery mechanisms as longer lasting and more resilient to change than regulatory cost recovery vehicles. Consequently, such mechanisms lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors.

Illustration Of The PPA Adjustment Methodology

The calculations of the debt equivalents, implied interest expense, depreciation expense, and adjusted financial metrics, using risk factors, are illustrated in the following example:

Example Of Power-Purchase Agreement Adjustment

($000s)	Assumption	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Cash from operations	2,000,000						
Funds from operations	1,500,000						
Interest expense	444,000						
Directly issued debt							
Short-term debt	600,000						
Long-term due within one year	300,000						
Long-term debt	6,500,000						
Shareholder's Equity	6,000,000						
Fixed capacity commitments	600,000	600,000	600,000	600,000	600,000	600,000	4,200,000*
NPV of fixed capacity commitments							
Using a 6.0% discount rate	5,030,306						
Application of an assumed 25% risk factor	1,257,577						
Implied interest expense¶	75,455						
Implied depreciation expense	74,545						
Unadjusted ratios							
FFO to interest (x)	4.4						
FFO to total Debt (%)	20.0						
Debt to capitalization (%)	55.0						
Ratios adjusted for debt imputation							
FFO to interest (x)§	4.0						
FFO to total debt (%)**	18.0						
Debt to capitalization (%)¶¶	59.0						

*Thereafter approximate years: 7. ¶The current year's implied interest is subtracted from the product of the risk factor multiplied by the current year's capacity payment. §Adds implied interest to the numerator and denominator and adds implied deprecation to FFO. **Adds implied depreciation expense to FFO and implied debt to reported debt. ¶¶Adds implied debt to both the numerator and the denominator. FFO--Funds from operations. NPV--Net present value.

Short-Term Contracts

Standard & Poor's has abandoned its historical practice of not imputing debt for contracts with terms of three years or less. However, we understand that there are some utilities that use short-term PPAs of approximately one year or less as gap fillers pending the construction of new capacity. To the extent that such short-term supply arrangements represent a nominal percentage of demand and serve the purposes described above, we will neither impute debt for such contracts nor provide evergreen treatment to such contracts.

Evergreen Treatment

The NPV of the fixed obligations associated with a portfolio of short-term or intermediate-term contracts can lead to distortions in a utility's financial profile relative to the NPV of the fixed obligations of a utility with a portfolio of PPAs that is made up of longer-term commitments. Where there is the potential for such distortions, rating committees will consider evergreen treatment of existing PPA obligations as a scenario for inclusion in the rating analysis. Evergreen treatment extends the tenor of short- and intermediate-term contracts to reflect the long-term obligation of electric utilities to meet their customers' demand for electricity.

While we have concluded that there is a limited pool of utilities whose portfolios of existing and projected PPAs don't meaningfully correspond to long-term load serving obligations, we will nevertheless apply evergreen treatment in those cases where the portfolio of existing and projected PPAs is inconsistent with long-term load-serving obligations. A blanket application of evergreen treatment is not warranted.

To provide evergreen treatment, Standard & Poor's starts by looking at the tenor of outstanding PPAs. Others can look to the "commitments and contingencies" in the notes to a utility's financial statements to derive an approximate tenor of the contracts. If we conclude that the duration of PPAs is short relative to our targeted tenor, we would then add capacity payments until the targeted tenor is achieved. Based on our analysis of several companies, we have determined that the evergreen extension of the tenor of existing contracts and anticipated contracts should extend contracts to a common length of about 12 years.

The price for the capacity that we add will be derived from new peaker entry economics. We use empirical data to establish the cost of developing new peaking capacity and reflect regional differences in our analysis. The cost of new capacity is translated into a dollars per kilowatt-year (kW-year) figure using a weighted average cost of capital for the utility and a proxy capital recovery period.

Analytical Treatment Of Contracts With All-In Energy Prices

The pricing for some PPA contracts is stated as a single, all-in energy price. Standard & Poor's considers an implied capacity price that funds the recovery of the supplier's capital investment to be subsumed within the all-in energy price. Consequently, we use a proxy capacity charge, stated in $/kW, to calculate an implied capacity payment associated with the PPA. The $/kW figure is multiplied by the number of kilowatts under contract. In cases of resources such as wind power that exhibit very low capacity factors, we will adjust the kilowatts under contract to reflect the anticipated capacity factor that the resource is expected to achieve.

We derive the proxy cost of capacity using empirical data evidencing the cost of developing new peaking capacity. We will reflect regional differences in our analysis. The cost of new capacity is translated into a $/kW figure using a weighted average cost of capital and a proxy capital recovery period. This number will be updated from time to time to reflect prevailing costs for the development and financing of the marginal unit, a combustion turbine.

Transmission Arrangements

In recent years, some utilities have entered into long-term transmission contracts in lieu of building generation. In some cases, these contracts provide access to specific power plants, while other transmission arrangements provide access to competitive wholesale electricity markets. We have concluded that these types of transmission arrangements represent extensions of the power plants to which they are connected or the markets that they serve. Irrespective of whether these transmission lines are integral to the delivery of power from a specific plant or are conduits to wholesale markets, we view these arrangements as exhibiting very strong parallels to PPAs as a substitute for investment in power plants. Consequently, we will impute debt for the fixed costs associated with long-term transmission contracts.

PPAs Treated As Leases

Several utilities have reported that their accountants dictate that certain PPAs need to be treated as leases for accounting purposes due to the tenor of the PPA or the residual value of the asset upon the PPA's expiration. We have consistently taken the position that companies should identify those capacity charges that are subject to operating lease treatment in the financial statements so that we can accord PPA treatment to those obligations, in lieu of lease treatment. That is, PPAs that receive operating lease treatment for accounting purposes won't be subject to a 100% risk factor for analytical purposes as though they were leases. Rather, the NPV of the stream of capacity payments associated with these PPAs will be reduced by the risk factor that is applied to the utility's other PPA commitments. PPAs that are treated as capital leases for accounting purposes will not receive PPA treatment because capital lease treatment indicates that the plant under contract economically "belongs" to the utility.

Evaluating The Effect Of PPAs

Though history is on the side of full cost recovery, PPAs nevertheless add financial obligations that heighten financial risk. Yet, we apply risk factors that reduce debt imputation to recognize that utilities that rely on PPAs transfer significant risks to ratepayers and suppliers.

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REVISED MAY 2007

Hawaiian Electric Company, Inc.
2007 Purchase Power Credit Impact Using the Standard & Poors Method
Debt Equivalent ($000)

	A	B	C	D
	Debt Equivalent			
	Beginning of Year 2007	End of Year 2007	Average	Interest Equivalent (B x 6%)
AES *	299,865	287,983	293,924	17,279
Kalaeloa **	144,734	136,759	140,746	8,206
H Power **	30,628	28,948	29,788	1,737
Total	475,226	453,690	464,458	27,221

S&P Risk Factor of	50%
Interest Equivalent at	6%

* Revised AES capacity payments to account for leap year (e.g. 2008, 2012, 2016, 2020).
** Revised Kalaeloa & H Power termination dates to assume 12 years beyond forecast year (e.g. 2007 + 12 = 2019), to account for S&P's evergreen treatment.
Future capacity payments beyond the termination dates are based on the proxy peaker value of $136/kw-yr.

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AES
Credit Impact Using the Standard & Poors Method
($000's)

S&P Risk Factor of	50%
Interest Equivalent at	6%

Annual Capacity Payment for non-major maint years[1]	59,100
Monthly Capacity Payment for non-major maint years[2]	4,925
Annual Capacity Payment for non-major maint years (leap year)[1]	59,262
Monthly Capacity Payment for non-major maint years (leap year)[2]	4,938
Annual Capacity Payment for major maint years[1]	56,318
Monthly Capacity Payment for major maint years[2]	4,693
End Month of Capacity Payments	Aug-22

		A	B	C = A x B
		Present Value Remaining Pmts	Risk Factor	Debt Equivalent
Balance at	1/1/2007	599,729	50%	299,865
	1/1/2008	575,967	50%	287,983

[1] Based on 4.4095 cents per available kwh and a firm capacity commitment of 180,000kW. Assumes 85% availability on non-major maintenance years, and 81% availability in years of major maintenance.

[2] Monthly payments made in arrears; calculated at the beginning of the next month.

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Kalaeloa
Credit Impact Using the Standard & Poors Method
($000's)

S&P Risk Factor of	50%
Interest Equivalent at	6%

Annual Capacity Payment[1]	32,719	
Monthly Capacity Payment[2]	2,727	
Annual Capacity Payment (beyond termination date)[3]	28,288	
End Month of Capacity Payments	Dec-19	Maturity date adjusted for S&P's evergreen treatment

		A	B	C = A x B
		Present Value Remaining Pmts	Risk Factor	Debt Equivalent
Balance at	1/1/2007	289,467	50%	144,734
	1/1/2008	273,519	50%	136,759

[1] Based on $164.35 per kW for the first 180,000kW of capacity, and $112 per kW for all kW of capacity above 180,000 kW (up to a maximum of 28 MW).

[2] Monthly payments made at the beginning of the month.

[3] Based on new peaker proxy unit $136 per kW/yr for the 180,000kW + 28,000kW of capacity (total of 208,000kW).

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H Power
Credit Impact Using the Standard & Poors Method
($000's)

S&P Risk Factor of	50%
Interest Equivalent at	6%

Annual Capacity Payment[1]	6,944	
Monthly Capacity Payment[2]	579	
Annual Capacity Payment (beyond termination date)[3]	6,256	
End Month of Capacity Payments	Dec-19	Maturity date adjusted for S&P's evergreen treatment

		A Present Value Remaining Pmts	B Risk Factor	C = A x B Debt Equivalent
Balance at	1/1/2007	61,255	50%	30,628
	1/1/2008	57,895	50%	28,948

[1] Based on 4.89 cents per kwh for 46 MW capacity during on-peak hours at 90% availability.

[2] Monthly payments made in arrears.

[3] Based on new peaker proxy unit $136 per kW/yr for the 46,000kW of capacity.

REVISED MAY 2007

Hawaiian Electric Company, Inc.
Financial Ratios

Test Year 2007	NO Rate Increase	WITH Rate Increase
Funds from Operations Interest Coverage *	2.44 x	3.81 x
Funds from Operations / Average Total Debt *	9%	17%
Total Debt / Total Capital *	59%	59%
Total Debt / Total Capital without Purchased Power Debt Equivalent	45%	45%

2005 Actual

Total Debt / Total Capital *	57%
Total Debt / Total Capital without Purchased Power Debt Equivalent	47%

* These ratios take into account the debt equivalent (off-balance sheet purchased power and operating lease obligations), and related implied interest and implied depreciation.

Financial Ratios in Comparison to S&P Rating Guidelines

Business Profile = 5

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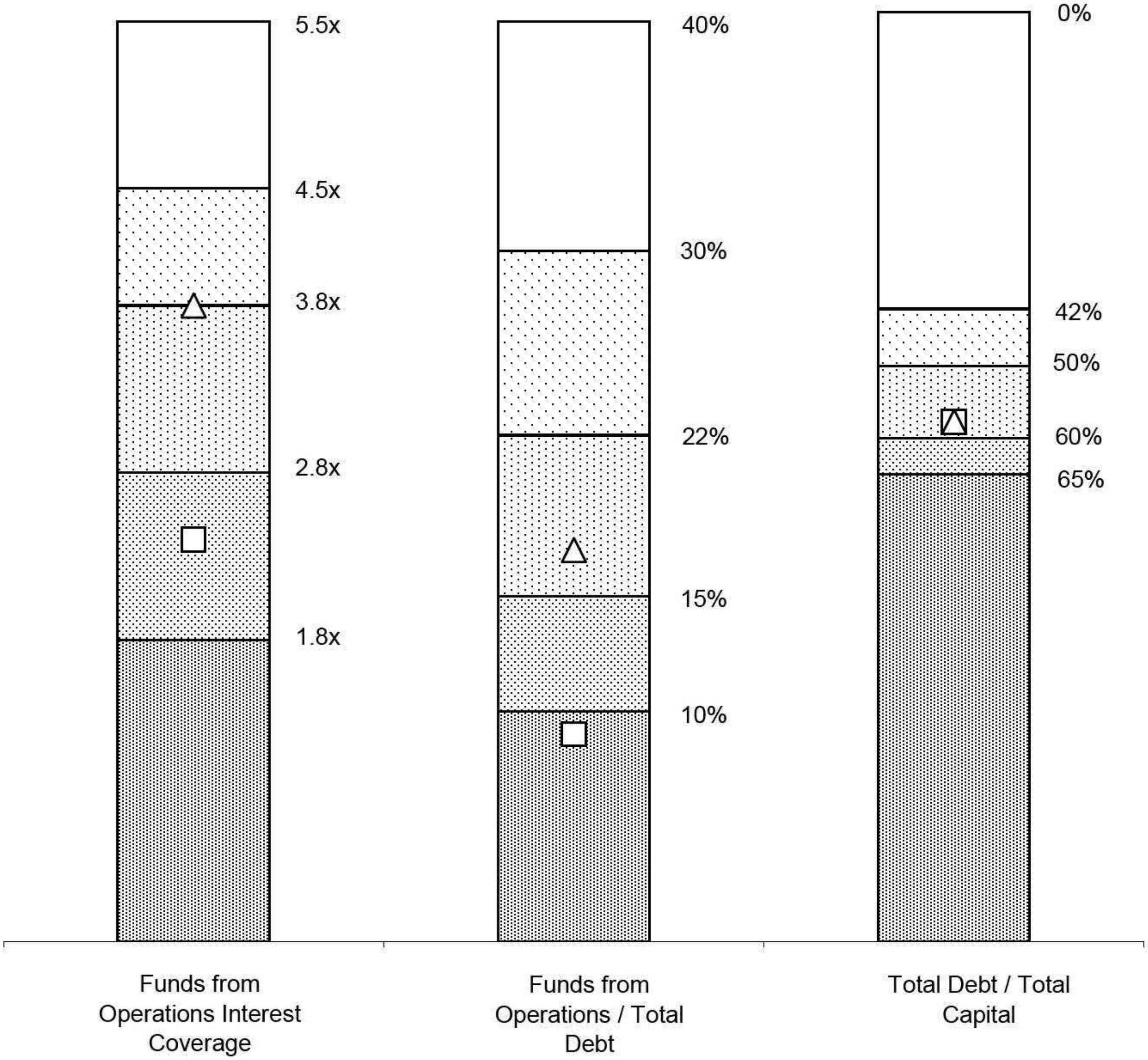

	Funds from Operations Interest Coverage	Funds from Operations / Total Debt	Total Debt / Total Capital
HECO w/ Rate Increase	3.8 x	17%	59%
HECO w/out Rate Increase	2.4 x	9%	59%

- AA
- A
- BBB
- BB
- Below BB
- △ HECO with Rate Increase
- □ HECO without Rate Increase

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Hawaiian Electric Company, Inc.
Test Year 2007

Income Statement
NO Rate Increase
Based on 11.25% Earned Return on Common Equity

	$ in thousands	HECO Reference
Operating Income	24,058	2302
AFUDC	4,994	1907
Annual Debt Requirement:		
Short-term Debt ($38,971 x 5.0%)	1,949	1902
Long-term Debt	29,267	1903
Hybrid	2,059	1904
Total Annual Debt Requirement	33,275	
Net Income	(4,223)	
Annual requirement on Preferred Stock	1,135	1905
Net Income for Common	(5,358)	

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Hawaiian Electric Company, Inc.
Test Year 2007

Funds from Operations Interest Coverage
NO Rate Increase & WITH Debt Equivalent
Based on 11.25% Earned Return on Common Equity

	$ in thousands		HECO Reference
Operating Income	24,058		2302
Depreciation	79,736		2302
Implied Depreciation for Purchased Power Commitments	22,160		May 2007 Update
Deferred Income Taxes	(6,181)		WP-2302, p.12
Amortization of State ITC	(1,321)		2302
State Capital Goods Excise Credit & PV Tax Credit	3,212		WP-2302, p.12
Interest on OBS Debt - Purchased Power Commitments [1]	27,221		May 2007 Update
Interest on OBS Debt - Operating Leases [1]	1,042		Per calculation from Budgets Division
Total	149,927	A	
Total Debt Requirement (ST, LT & Hybrids)	33,275		WP-1913, p. 1
Interest on OBS Debt - Purchased Power Commitments [1]	27,221		May 2007 Update
Interest on OBS Debt - Operating Leases [1]	1,042		Per calculation from Budgets Division
	61,538	B	
Fund from Operations Interest Coverage (A)/(B)	2.44	x	

[1] Interest on off-balance sheet (OBS) debt is not reflected in the book numbers.
Interest on the OBS debt related to purchased power commitments and operating leases represents the interest expense that the Company would have incurred if the debt equivalent related to purchased power commitments and operating leases were reflected as a debt obligation on the Company's balance sheet.

REVISED MAY 2007

Hawaiian Electric Company, Inc.
Test Year 2007

Funds from Operations / Average Total Debt
NO Rate Increase & WITH Debt Equivalent
Based on 11.25% Earned Return on Common Equity

	$ in thousands		HECO Reference
Operating Income	24,058		2302
Depreciation	79,736		2302
Depreciation adjustment for Operating Leases	3,265		Per calculation from Budgets Division
Implied Depreciation for Purch Pwr Commitments	22,160		May 2007 Update
Deferred Income Taxes	(6,181)		WP-2302, p.12
Amortization of State ITC	(1,321)		2302
State Capital Goods Excise Credit & PV Tax Credit	3,212		WP-2302, p.12
Interest Expense:			
Short-term interest	(1,949)		1902
Long-term interest	(27,667)		1903
Hybrid interest	(2,051)		1904
Total Interest Expense	(31,667)		
Total	93,262	A	
Average Debt:			
Short-term Debt	38,971		1902
Long-term Debt [1]	499,747		1903 & WP-1903, p.6
Hybrid [2]	31,546		1904
OBS Debt (50%) - Purch Pwr Commitments [3]	464,458		May 2007 Update
OBS Debt - Operating Leases [3]	17,361		Per calculation from Budgets Division
Average Total Debt	1,052,083	B	
FFO to Ave Total Debt Ratio (A)/(B)	0.09		

[1] Net of unamortized discount on outstanding revenue bonds.

[2] Excludes unamortized costs.

[3] Off-balance sheet (OBS) debt is not reflected in the book numbers. Represents the imputed debt of the Company's purchased power commitments and operating leases.

REVISED MAY 2007

Hawaiian Electric Company, Inc.
Test Year 2007

Total Debt / Total Capital
NO Rate Increase & WITH Debt Equivalent
Based on 11.25% Earned Return on Common Equity

	$ in thousands		HECO Reference
Capitalization Balances at Year-End:			
Total Debt:			
Short-term Debt	0		1902
Long-term Debt [1]	549,800		1903 & WP-1903, p.6
Hybrid Securities [2]	31,546		1904
Total Debt	581,346		
OBS Debt (50%) - Purch Pwr Commitments [3]	453,690		May 2007 Update
OBS Debt - Operating Leases [3]	15,361		Per calculation from Budgets Division
Revised Total Debt	1,050,397	A	
Preferred Stock [2]	22,293		1905
Common Stock	710,438		1906
Total Capital	1,783,128	B	
Total Debt / Total Capital Ratio (A)/(B)	0.59		

[1] Net of unamortized discount on outstanding revenue bonds.
[2] Excludes unamortized costs.
[3] Off-balance sheet (OBS) debt is not reflected in the book numbers. Represents the imputed debt of the Company's purchased power commitments and operating leases.

REVISED MAY 2007

Hawaiian Electric Company, Inc.
Test Year 2007

Total Debt / Total Capital
NO Rate Increase & WITHOUT Purchased Power Debt Equivalent
Based on 11.25% Earned Return on Common Equity

	$ in thousands		HECO Reference
Capitalization Balances at Year-End:			
Total Debt:			
Short-term Debt	0		1902
Long-term Debt [1]	549,800		1903 & WP-1903, p.6
Hybrid Securities [2]	31,546		1904
Total Debt	581,346		
OBS Debt (0%) - Purch Pwr Commitments [3]	0		
OBS Debt - Operating Leases [3]	15,361		Per calculation from Budgets Division
Revised Total Debt	596,707	A	
Preferred Stock [2]	22,293		1905
Common Stock	710,438		1906
Total Capital	1,329,438	B	
Total Debt / Total Capital Ratio (A)/(B)	0.45		

[1] Net of unamortized discount on outstanding revenue bonds.
[2] Excludes unamortized costs.
[3] Off-balance sheet (OBS) debt is not reflected in the book numbers. Represents the imputed debt of the Company's purchased power commitments and operating leases.

REVISED MAY 2007

Hawaiian Electric Company, Inc.
Test Year 2007

Income Statement
WITH Rate Increase
Based on 11.25% Earned Return on Common Equity

	$ in thousands	HECO Reference
Operating Income	108,317	2302
AFUDC	4,994	1907
Annual Debt Requirement:		
Short-term Debt ($38,971 x 5.0%)	1,949	1902
Long-term Debt	29,267	1903
Hybrid	2,059	1904
Total Annual Debt Requirement	33,275	
Net Income	80,036	
Annual requirement on Preferred Stock	1,135	1905
Net Income for Common	78,901	

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Hawaiian Electric Company, Inc.
Test Year 2007

Funds from Operations Interest Coverage
WITH Rate Increase & WITH Debt Equivalent
Based on 11.25% Earned Return on Common Equity

	$ in thousands		HECO Reference
Operating Income	108,317		2302
Depreciation	79,736		2302
Implied Depreciation for Purchased Power Commitments	22,160		May 2007 Update
Deferred Income Taxes	(6,181)		WP-2302, p.12
Amortization of State ITC	(1,321)		2302
State Capital Goods Excise Credit & PV Tax Credit	3,212		WP-2302, p.12
Interest on OBS Debt - Purchased Power Commitments [1]	27,221		May 2007 Update
Interest on OBS Debt - Operating Leases [1]	1,042		Per calculation from Budgets Division
Total	234,186	A	
Total Debt Requirement (ST, LT & Hybrids)	33,275		WP-1913, p. 1
Interest on OBS Debt - Purchased Power Commitments [1]	27,221		May 2007 Update
Interest on OBS Debt - Operating Leases [1]	1,042		Per calculation from Budgets Division
	61,538	B	
Fund from Operations Interest Coverage (A)/(B)	3.81	x	

[1] Interest on off-balance sheet (OBS) debt is not reflected in the book numbers.
Interest on the OBS debt related to purchased power commitments and operating leases represents the interest expense that the Company would have incurred if the debt equivalent related to purchased power commitments and operating leases were reflected as a debt obligation on the Company's balance sheet.

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Hawaiian Electric Company, Inc.
Test Year 2007

Funds from Operations / Average Total Debt
WITH Rate Increase
Based on 11.25% Earned Return on Common Equity

	$ in thousands		HECO Reference
Operating Income	108,317		2302
Depreciation	79,736		2302
Depreciation adjustment for Operating Leases	3,265		Per calculation from Budgets Division
Implied Depreciation for Purch Pwr Commitments	22,160		May 2007 Update
Deferred Income Taxes	(6,181)		WP-2302, p.12
Amortization of State ITC	(1,321)		2302
State Capital Goods Excise Credit & PV Tax Credit	3,212		WP-2302, p.12
Interest Expense:			
Short-term interest	(1,949)		1902
Long-term interest	(27,667)		1903
Hybrid interest	(2,051)		1904
Total Interest Expense	(31,667)		
Total	177,521	A	
Average Debt:			
Short-term Debt	38,971		1902
Long-term Debt [1]	499,747		1903 & WP-1903, p.6
Hybrid [2]	31,546		1904
OBS Debt (50%) - Purch Pwr Commitments [3]	464,458		May 2007 Update
OBS Debt - Operating Leases [3]	17,361		Per calculation from Budgets Division
Average Total Debt	1,052,083	B	
FFO to Ave Total Debt Ratio (A)/(B)	0.17		

[1] Net of unamortized discount on outstanding revenue bonds.
[2] Excludes unamortized costs.
[3] Off-balance sheet (OBS) debt is not reflected in the book numbers. Represents the imputed debt of the Company's purchased power commitments and operating leases.

REVISED MAY 2007

Hawaiian Electric Company, Inc.
Test Year 2007

Total Debt / Total Capital
WITH Rate Increase & WITH Debt Equivalent
Based on 11.25% Earned Return on Common Equity

	$ in thousands		HECO Reference
Capitalization Balances at Year-End:			
Total Debt:			
Short-term Debt	0		1902
Long-term Debt [1]	549,800		1903 & WP-1903, p.6
Hybrid Securities [2]	31,546		1904
Total Debt	581,346		
OBS Debt (50%) - Purch Pwr Commitments [3]	453,690		May 2007 Update
OBS Debt - Operating Leases [3]	15,361		Per calculation from Budgets Division
Revised Total Debt	1,050,397	A	
Preferred Stock [2]	22,293		1905
Common Stock	710,438		1906
Total Capital	1,783,128	B	
Total Debt / Total Capital Ratio (A)/(B)	0.59		

[1] Net of unamortized discount on outstanding revenue bonds.
[2] Excludes unamortized costs.
[3] Off-balance sheet (OBS) debt is not reflected in the book numbers. Represents the imputed debt of the Company's purchased power commitments and operating leases.

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Hawaiian Electric Company, Inc.
Test Year 2007

Total Debt / Total Capital
WITH Rate Increase & WITHOUT Purchased Power Debt Equivalent
Based on 11.25% Earned Return on Common Equity

	$ in thousands		HECO Reference
Capitalization Balances at Year-End:			
Total Debt:			
Short-term Debt	0		1902
Long-term Debt [1]	549,800		1903 & WP-1903, p.6
Hybrid Securities [2]	31,546		1904
Total Debt	581,346		
OBS Debt (0%) - Purch Pwr Commitments [3]	0		
OBS Debt - Operating Leases [3]	15,361		Per calculation from Budgets Division
Revised Total Debt	596,707	A	
Preferred Stock [2]	22,293		1905
Common Stock	710,438		1906
Total Capital	1,329,438	B	
Total Debt / Total Capital Ratio (A)/(B)	0.45		

[1] Net of unamortized discount on outstanding revenue bonds.
[2] Excludes unamortized costs.
[3] Off-balance sheet (OBS) debt is not reflected in the book numbers. Represents the imputed debt of the Company's purchased power commitments and operating leases.

Worksheet to Calculate Implied Depreciation Adj for Financial Ratios

Capacity Payments in 2007:		
AES	59,100	
Kalaeloa	32,719	
Hpower	6,944	
Total	98,763	a
Risk Factor	50%	b
Implied Interest for PPA in 2007	27,221	c
Implied Depreciation for 2007	22,160	d = (a x b) - c

DOD-IR-69

Sekimura Direct, p. 39, ll. 21, 22.

a) Please provide documentation from Standard & Poor's which shows that the manner in which that bond rating agency calculates HECO's PPA debt imputation comports with that included in the Company's testimony in this proceeding.

b) If purchased power contracts add debt and financial risk to integrated companies, please explain why transmission and distribution utilities, which purchase 100% of their power, have lower business risk profiles and lower leverage requirements than integrated electrics.

HECO Response:

a. HECO's PPA debt equivalent calculation that was presented in Direct Testimony (T-19), HECO-WP-1913, pages 11 through 14, was based on our understanding of S&P's debt equivalent calculation, as explained in S&P's Ratings Direct for HECO, dated May 31, 2006 (see HECO-1914, page 4). HECO's PPA debt equivalent calculation presented in Direct Testimony (T-19) assumed a discount rate of 6% and a 30% risk factor, based on the information provided by S&P in this report.

However, based on S&P's recent publication dated May 7, 2007 (see HECO's response to DOD-IR-68), it is our understanding that HECO's firm capacity purchased power contracts are now assigned a 50% risk factor, rather than the 30% risk factor previously used by S&P, and S&P will also apply evergreen treatment which extends expected payments to a minimum of twelve years. The documentation from S&P which explains S&P's methodology for imputing debt for purchased power agreements is provided in HECO's response to DOD-IR-68. The Company also presents revised 2007 financial ratios in HECO's response to DOD-IR-68 based on the Company's understanding of S&P's current methodology of imputing debt for purchase power agreements and adjustments made to the financial ratios.

b. As discussed on page 2 of S&P's May 7, 2007 article, the impact of purchase power contracts on a utility's risk profile is dependent on the level of assurance of cost recovery. In the article, S&P states:

> "For example, an unregulated energy company that has entered into a tolling arrangement with a third-party supplier would be assigned a 100% risk factor. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers. This type of arrangement is frequently found among regulated utilities that act as conduits for the delivery of a third party's electricity and essentially deliver power, collect charges, and remit revenues to the suppliers. These utilities have typically been directed to sell all their generation assets, are barred from developing new generation assets, and the power supplied to their customers is sources through a state auction or third parties, leaving the utilities to act as intermediaries between retail customers and the electricity suppliers."

DOD-IR-70

<u>Sekimura Direct, pp. 41.42.</u>

Is Ms. Sekimura aware of any other electric utility that issues all of its long-term debt in the form of non-taxable revenue bonds?

HECO Response:

I do not know of any other electric utility that issues all of its long-term debt in the form of non-taxable revenue bonds.